APPENDICES

Policy Subcommittee Issues

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Status
26	XML versus EDI What is XML? Should this be considered for a best practice for the Arizona's model?	1/25/00		1/25/00 – This is an issue for the policy group to investigate. This is not a transport mechanism, it is defined as a data structure. 2/1/00 – Ray Wensel, Excelergy, offered to coordinate a presentation to the PSWG on XML. Evelyn Dryer will address with ACC and possibly get this on a large group agenda.	Pending
27	Companies are defining 'workdays' for time frames for work to be completed. The problem is that some companies are including holidays that are not recognized by others. Need to define 'standardized workday'. Suggested Resolution: NERC holidays recognized but modified. If a NERC holiday falls on a Saturday it is recognized on a Friday and if the holiday falls on a Sunday it is recognized on a Monday. Standardized Work Days: Any day except Saturday/Sunday or NERC holiday. If holiday falls on a Saturday it is recognized on a Friday. If the holiday falls on a Sunday, it is recognized on a Monday.	1/26/00	2/29/00	1/26/00 For example: In some territories Columbus Day, MLK Day are recognized as holidays and are excluded from a workday calculation. This could effect time periods defined for metering, meter reading, Consolidated billing and enrollment. 2/1/00 – Standardization of holidays may not be possible. Suggestion 1: If a Federal or State Holidays are defined, these could be used as an exception to workdays for ALL participants. Suggestion 2: Use NERC definition of holiday. Evelyn Dryer to provide to the Policy Group. Action Item for Policy Group: All participants need to take these suggestions to their organizations to see what will work. Items to consider: Cash flow, bill cycles, read cycles, settlement etc. Also, Please bring a list of your organizations recognized holidays. Be preparted to discuss impact to company's if we recommend NERC holidays only, OR if we were to recognize all State and Federal Holidays. Due by 2/15/00 Darrell Pichoff to bring list of Postal/Federal Holidays. Steve Olea to bring list of State Holidays. 2/16/00 – Pending Resolution (see UDC holiday matrix – enclose with minutes).	Resolve d
29	Are 997s required for all transactions? Is that going to be our recommendation for the Arizona standards?	1/27/00		1/27/00 997s are an industry standard transaction (EDI syntax validation) 2/1/2000 – Yes a 997 acknowledgement is required on all standardized EDI transaction sets. Policy group will recommend that the level of acknowledgement should be determined by the individual trading partners. 2/8/00 – Is a 997 required for meter data that is extracted from a MRSP web site?	Pending

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32	What is the true costs of CT/VT (PT) if an ESP wants to buy the equipment? Cost to replace equipment at today's market price OR cost to UDC and depreciated by years since installation.	1/27/00	See issue 44 &54	#23,44, & 54: Renee will have more information regarding these items for the 3/8/00 meeting. 3/7/00 (ref: 32,44,&54) Suggestions: lease CT/PT/VT's or have a long- term purchase plan. APSES/Jim W: will contact California to see how they handle CT PT ownership issues. Action: UDC's discuss w/ companies lease agreements, long term pymt plans and their defense on why want to own them. Action: Clarify rule 14-2-1612-K10. Action: All market participants review rule 14-2-1612-K10. Determine if want to interpret/re-word using UDC shall own, UDC shall not own, may own or may own at the discretion of the customer. Be prepared to defend/come to a consensus. 3/14/00 Costs range from roughly $230-$3500 Action: ESP's to provide more detail regarding the long-term payment plan (how much/how long). APS/TEP will not support a leasing option APS will support the payment plan option only if for the life of the contract between the ESP & customer. 3/22/00 Discussion: ESP's don't want to resort to a lease/pymt plan option until the issue of the UDC's maintaining ownership of the CT/PT's has been resolved.	Pending agenda item for 3/27/00
44	Clarify ownership of CT and VTs (PT) based on voltage level.	2/3/00	See issue 32 & 54	2/3/00 Group will refer to ACC Rules.	Pending Agenda Item for 3/14/00

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54	Ownership of Current Transformers (CTs) and Voltage Transformers (VTs formerly known as PTs) is not consistent across UDCs.	1/25/00	See issue 32 & 44	: The ACC rules for Direct Access and the Electric Competition Act provide for a UDC to own and maintain both CTs and VTs. However, the interpretation of these rules differs by UDC. One UDC mandates that CT/VTs be purchased by the Customer or the ESP/MSP if they are below a certain voltage size. Another UDC maintains ownership and maintenance responsibilities of CT/VTs for all Customers, and the third major UDC maintains ownership of the CT/VTs, but requires the ESP/MSP to maintain them. This inconsistency creates difficulty for an ESP, especially when dealing with Customers with facilities in more than one service territory. Requiring the ESP/MSP or Customer to purchase the equipment also adds a potentially significant cost and may be a barrier for many Customers who otherwise might seek alternative suppliers. In California, CT/VTs are treated as part of the UDC distribution system and ownership and maintenance responsibilities are retained by the UDC. RECOMMENDATION: The Metering Working Group should look at the intent of the language in the competition rules regarding equipment ownership and make a determination on CT/VT ownership that all UDCs can implement on a consistent basis. 3/14/00 Action: APS/TEP will investigate whether they can agree to own CT/VT's above the secondary voltage level (600 volts or less). (This will not require a rule change…it will require a tariff change). Action: APS will determine amount of primary customer accounts. Issue: Can the customer own their own CT/PT's? Need clarification of the rules.	Pending Agenda Item for 3/28/00
34	There is no formalized process to report meter exceptions between UDCs and ESPs. (Examples: agreement metering programming, if MI/MAC forms are not completely filled out, etc. See MADEN for details on exception reasons.)	1/27/00	See Issue 52	Janie will provide information regarding this. Proposed Resolutions: It has been agreed that a formal communication method (similar to MADEN) will be utilized. The details of what data elements/guidelines will be discussed in both the metering & billing subcommittees.	Pending Resoluti on
52	UDCs and market participants need a clearly-defined communication process for promptly communicating and resolving problems with data, meters, or bills among ESPs, MSPs, MRSPs, and the UDCs	1/25/00	See Issue 34	This process should be initiated by any participant to establish communication to solve the problem within a defined time frame, if possible, and, if necessary, to maintain communication until root cause analysis is complete. The a standardized process should be implemented immediately by each participant and automated by all parties as soon as possible. An example of the California "MADEN" process is attached to the original change control document. This process will reduce meter and data errors that cause billing errors and delays in billing and receiving revenue. It will help provide customer satisfaction by reducing billing questions and complaints to both UDCs and ESPs.	Pending 3/28/00 Agenda

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38	Will the UDCs allow ESPs to interrogate meters on non-DA customers for load research purposes/ billing option purposes?	1/27/00		Janie will clarify at the 3/13/00 meeting. Details on Issue: Customer is not DA and wants load research data for informational purposes Example: ESP may be taking multiple customer accounts but not all of them. The ESP would like a secondary password to review this information so they can provide the information of all sites (even those not going DA) to the customer. If there is no IDR meter at the site, the customer would need to initiate an IDR meter from the UDC and pay the associated costs.	Pending
46	All Arizona EDI (DASRs, 867, 810, 650) should utilize GMT for the business transactions and local time for the enveloping. To avoid problems and unnecessary costs to conform to national standardization in the future, standard time references should be implemented immediately by each UDC, and EDI mapping can be phased in.	1/25/00		This change would help market participants, particularly MDMAs/MRSPs, to save costs by not having to adapt their systems to Arizona's unique requirements. **Action Item: All participants need to see what the use of GMT will do to their systems.** **2/16/00** **Proposal:** All participants will use GMT format for all transactions that require a time stamp**.** **Action:** find out how long the conversion to the GMT format will take. The group came to consensus **Recommendation:** All Arizona EDI transaction set data content will utilize GMT time and GMT time code. The enveloping of the EDI transactions will utilize the sender's local time. Implementation Issue: This recommendation refers to the ACC rule that states data transmission will be sent in Arizona time. The Policy Group will recommend a change to the ACC Rules. 3/28/00 Determined this is not a rule change it is actually noted in the CC&N's. Action: Paul will talk with the ACC to determine what needs to take place to get the issue resolved. Can staff just send a notice to the existing certified entities advising them of the change to GMT?	Resolved

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47	Standardization of Billing Options (ESP and UDC consolidated billing as well as Dual billing) from all UDCs should be implemented immediately to provide customer choice. Include related changes or impacts to other processes or procedures.	1/25/00		A working group of market participants should study the intent of the Commission Rules and make a determination that applies to all UDCs. The Terms and Conditions for credit, payments and partial payments, and other billing processes should be standardized for all UDCs. During the direct access rulemaking process, an earlier working group discussed whether billing options should be discretionary, but no consistent position was reached. Market participants need to clarify the procedures for consistency among UDCs. In order to develop a viable direct access market, the limitations on customer choice caused by differences in billing procedures among UDCs will be removed. Customer confusion and criticism will be reduced, and ESPs will have flexibility to meet individual customer needs.	Pending
48	For all Billing and Metering data, UDCs should employ the same rule and/or formula for rounding up data and rounding in calculations. The business process should be implemented immediately by each UDC. Include related changes or impacts to other processes or procedures. Resolution: No standardization needed.	1/25/00	2/29/00	In order to develop a viable direct access market, the burdens and costs caused by differences in data and billing procedures among UDCs will be removed. Customer confusion will be reduced. Action Items: All participants need to investigate what their rounding processes are on meter reading and billing. They also need to investigate how their CIS/MDMA systems handle rounding. 2/16/00 Jim will provide more examples to help define the issue. 2/22/00 Jim brought examples of rounding issues. Jim found that these issues were not widespread and the magnitude is fairly small. These issues will be discussed with the individual UDCs. Pending resolution at the 2/29/00 meeting	Resolved

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Status
55	UDC fees for Direct Access services (CISR, DASR, metering, meter reading, billing, settlement, etc.) are too high and not consistent between UDCs.	1/25/00		DISCUSSION: The 3 largest UDCs have proposed varying fees for Direct Access services, such as for meter information, for submitting Direct Access Service Requests, for meter installations or removals, for meter reading services, for consolidated and/or dual billing, and for settlement billing. These fees are, in some cases, excessively high and do not reflect the true marginal cost of providing these services. Many fees are required by one UDC, but not at all by the other UDCs. Even when required by all UDCs for the same service, the fees are not consistent and vary quite substantially. All of the additional fees provide an additional barrier to the development of a competitive market in Arizona. RECOMMENDATION: In order for a viable market to develop in Arizona, a group consisting of market participants should be tasked with determining which fees should be mandatory, which fees should be discretionary, and which fees should be deferred until the market has developed. This group should also recommend which costs could be recovered as part of base rates and which should be recovered in service fees. Finally, the group should recommend a consistent, cost-based methodology for calculating the costs to be recovered by the UDCs.	Pending

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Status
56	**Non-availability of local alternatives for providing competitively priced metering services.**	1/25/00	See Issue 28 & 36	Currently, there are very few Meter Service Providers (MSPs) or Meter Reading Service Providers (MRSPs) that have facilities and personnel in Arizona. Most of the certificated providers are based out-of-state and cannot, by ACC rules, subcontract with non-certificated personnel in the state. This potentially drives up the cost of some services that require personnel to travel to Arizona. Additionally, since the UDCs cannot provide competitive metering services beyond the year 2000, most have chosen not to provide a full menu of services during the year 2000. Both of these factors produce situations where the cost of providing competitive metering services are higher than they would be if they were provided by personnel already located in the state. The Policy Working Group should recommend that, to stimulate the market and the cost effective provision of competitive services, the following changes should be made: 1. UDCs should be allowed to provide competitive metering services at a competitive market price, and 2. MSP/MRSPs should be allowed to subcontract for services to qualified personnel, without having to make them employees of the company, as long as the certificated MSP/MRSP is still responsible for the work they perform. 3/14/00 Barb Klemstine will change the wording on the MSP qualifications/requirements that is attached to the CC&N in regards to item 3. She will include wording so that the MSP & their agents will be held to the same rules. White Paper Results: 1. TEP & APS agree – waiver will be needed 2. TEP & APS don't agree due to procurement & labor issues 3. TEP & APS agree with some clarification of the rules. Action: TEP & APS will begin working on a waiver for white paper issue #1 (non-residential load profile)	Pending agenda item for 4/18/00
56	**Non-availability of local alternatives for providing competitively priced metering services.**	1/25/00	See Issue 28 & 36	4/11/00 Be prepared to discuss item #2 (subcontracting) for the next meeting.	Pending Agenda 4/18/00

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Status
28	Clarification on when an UDC can be an MSP. Both sets of Direct Access rules have different definitions. (ACC Rules and HB 2663)	1/26/00	See Issue 56 & 36	1/26/00 For example, in APS territory they cannot be an MSP for any customer except under 20 kW and residential customer. Additionally, when are meter exchanges required within the service territories. 2/1/2000 – In service territory's governed by the ACC Competition Rules: See section R14-2-1615-B. On January 1, 2001 no affected utility can offer competitive services. Issue still remaining: What if there are no service providers offering these services at a competitive rate after 1/1/01 that make it cost effective for customers to switch? This is a Commission and Legislative issue. Barbara Klemstine: Will provide a proposal to the group next week showing why the UDC can be an MSP. Action: take Barbara's "white pages" to our companies to see if any problems/issues with the document. Be prepared to discuss next week. May need to create a waiver for this. Action: APS to determine implementation issues regarding issues #28, #36, & #56 Barry Scott does not want a rule written that the choice of the MSP has to be chosen by the ESP. It should be the customer's choice.	Pending There is still the issue remaining which will be included on the ACC report. Agenda Item for 3/21/00
36	ACC Rules Question: Can the UDC provide metering and installation services for DA customer? Short term and after January 1, 2001?	1/27/00	See issue # 56 & 28	**Action Item:** Participants need to read the ACC and HB2663 and be prepared to discuss issue**.**	Pending **Will appear on the 3/21/00 Agenda**
61	Who is responsible for tracking the performance of MSP and MRSP's? What is the process for communicating this information?	2/8/00			Pending
69	What is the enforceability of the recommended processes or rules of non-ACC jurisdictional entities?	2/17/00		Where does an ESP file noncompliance complaints for those entities that are not governed by the ACC rulings?	Pending
70	A utility can back-bill a 3rd party (if the 3rd party is at fault) up to 12 months (R14-212-/e3). This is only specific to the utility. Should the rule be applicable to other participants other than just the utility?	2/22/00		Should this Rule be modified to allow all parties providing meter data to be back-billed by the recipients of the incorrect data?	Pending

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73	Is NERC using Standard Central Time in Non-EDI transactions? Why is NERC using Standard Central Time and should we be using it?	2/29/00		3/7/00 Address once NERC has made their decision on which standard time to use. <u>Suggestions</u>: Send a letter to NERC recommending GMT. <u>Action:</u> talk w/ your companies to see if support the GMT format (issue #46) as a standard so can file for a joint waiver. E-mail to Evelyn by 3/13/00. Evelyn will write the waiver to present to the ACC. Yes, NERC is using Central Standard Time 3/28/00 Action: Shirley & Jim will flow out process' for converting data to Standard Time Zones.	Pending On 3/13/00 agenda
74	Navapahce will be submitting a report to the PSWG regarding what their business processes will be for DA.	3/2/00		How should this report be represented in the 6/15/00 ACC report? This opportunity may need to be offered to all cooperatives.	Pending
75	The UMI was presumed to be the national standard for identifying a single meter. However, it's not being used by any other state in the dereg market. Furthermore most of the EDI documents are not implementing a UMI number.	3/16/00	3/28/00	Representatives from New West Energy, APSES, 1st Point and Schlumberger are not using this number. It was suggested that this number no be implemented as an Arizona standard. 3/28/00 APSES does not need the UMI - Jim W advised that the UMI is not being used by MSP's (First Point & Schlumberger) in CA. - This is not an industry standard that we thought it would be. - No compelling reason for market participants to use the UMI standard. Proposition: Request that the Utilities Director remove the requirement of using the UMI standard from the 5/1/99 report.	Resolved
78	**There is no language in the rules keeping the MSP from contracting directly with the customers, how should this issue be addressed?**	3/28/00		System implications – Will the MSP have to submit DASR's?	Pending 4/25/00

Billing Subcommittee Issues

Resolved Issues

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Resolution
4	Invoice Start & End Date do we need to state on bill?	Oct 13, 1999	Oct 13, 1999	Rule Language R14-2-1617 States that "time period to which the reported information applies 2/2/2000 The proposed rule has changed. It was agreed that both parties shall disclose this information. Reference R14-2-210. Resolved. Revisited by the 2/2/00 Billing Subcom.
1	Tax Exempt: Does the ESP currently get Tax Exempt status on 810? Is the ESP required to have certificates for existing exempt customers?	Oct 13, 1999	Nov 10, 1999	Resolved. It is the end use customer responsibility to provide tax exemption status to each of their providers. 2/2/2000 Bill Rigsby – ACC will bring the tax statues to the Billing Subcom on 2/9/00 for clarification. This may be included in the recommendation. Resolved. Revisited on 2/2/00 by the Billing Subcom.
2	Credit/Debit Amount by record	Oct 13, 1999	Nov 10, 1999	This will be added to the Implementation Guide as an optional code. 2/2/2000 The above recommendation still applies. Resolved. Revisited on 2/2/00 by the Billing Subcom.
3	Balance (BAL) vs. Total monetary value summary (TDS) for invoice payment. Issue for UDC, they cannot bill past due charges, since they may not be aware of payment amounts and dates.	Oct 13, 1999	Nov 10, 1999	UDC will not send payment information to the ESP since the ESP is covering the customer's receivable to the UDC. 2/2/2000 Resolution still stands. UDC will send current charges only for ESP consolidated billing. 2/8/00 This issue will be looked at when the IG is written. Pending. Revisited by the 2/2/00 Billing Subcom.
5	Reason of Estimate - Do both parties need to give?	Oct 13, 1999	Nov 10, 1999	No. It is the Billers responsibility to print this in the bill using the 867 standard estimation reason codes. See Business Rules. 2/2/2000 Resolution stands. Resolved. Revisited by the 2/2/00 Billing Subcom.
11	Will ESPs want to partake in SurePay? (Debit ESPs Bank Account for monies owed to the UDC)	Oct 26, 1999	Nov 10, 1999	If so, it is a contractual agreement between the ESP and the UDC. 2/2/2000 Resolution Applies Resolved Revisited by the 2/2/00 Billing Subcom
12	3rd party Billing (Should UDC continue to offer?)	Oct 26, 1999	Nov 10, 1999	This is an arrangement that will need to be made between the Biller (in this case the ESP) and their customer. 2/2/2000 Resolution applies. Resolved Revisited by the 2/2/00 Billing Subcom

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Resolution
13	Payment Date appearing on customer's bill.	Oct 26, 1999	Nov 10, 1999	Payment Date, payment amount and payment received date will not be passed to the ESP on the 810 for printing on an ESP Consolidated Bill. 2/2/2000 Resolution applies. Since the UDC does not know when or if a payment is actually received from the customer in ESP Consolidate Billing, this information will not be passed. Resolved Revisited by the 2/2/00 Billing Subcom.
17	Will the ESPs support levelized UDC billing line items?	Dec 1, 1999	2/24/00	It could be a hindrance for a customer to go Direct Access (in the case of a large debit balance) the ESPs would not want this large debit balance passed to them for payment. More input from the ESPs and UDCs is needed. 2/2/2000 APS is planning to offer this option if they are the Billing entity. TEP is not planning to offer this billing option for DA Customers Barry Scott SSVEC I think any customer desiring to go to competitive access should settle all of their accounts with the UDC first. I believe if we will handle the process as we currently do for a customer going from one UDC to another we will be better off. 2/8/00 – SRP will offer Levelized to customers for UDC Consolidated and Dual billing for distribution charges only. APS doesn't offer Levelized for ESP Consolidated. TEP doesn't offer levelized billing for DA customer regardless of the billing option. **Proposal**: The ESP has the option to offer levelized billing to the end use customer. The UDC will not pass levelized billing line items for ESP Consolidated billing. 2/24/00 Above proposal accepted. Resolved
22	If a customer has a credit or debit balance on the bill when they switch to DA, is the utility obligated to refund that money?	2/2/2000	3/8/00	2/8/00 Levelized / Equalizer was briefly discussed regarding the debit or credit balances 2/24/00 In APS territory, they will final out the standard offer account and bill the customer separately if there is a debit. If the customer does not pay and is eligible for disconnect, they notify the ESP. If there is a credit they will refund this to the customer prior to the switch for DA. Pending Resolution: At the time the customer goes DA and they have a credit balance, the UDC is required to the refund the credit directly to the customer in accordance to their applicable Rules and Regulations. At the time the customer goes DA and the customer has a debit balance, it will be the sole responsibility of the UDC to collect the money from the customer.

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19	Once the troubleshooting process has taken place, and the UDC is estimateling (an MRSP did not deliver the data in a timely manner or the read could not be retrieved), should the UDC transmit the estimation reasons for the ESP Consolidated Bill.	2/2/2000	4/8/00	The group needs to specify under what conditions the UDC could estimate a bill and pass this information to the ESP. 2/24/00 Shirley Renfroe reported that the EDI 810 allows for an estimation reason code to be passed to the ESP. Proposed Resolution: If the MRSP fails to provide a meter read and the exception processing window has passed, the UDC may estimate and provide an indicator why the bill was estimated. The ESP is required to print this reason on UDC portion of the bill pursuant to Rule 14-2-210-6B. 3/8/00 Reason codes need to be developed before this can be resolved. 4/8/00 Resolution: We will use a reason code of: Meter Data not available
23	If the utility is holding a deposit for the customer and the customer switches to ESP consolidated billing, is the utility required to refund the entire deposit since the receivable is paid to the UDC by the ESP?	2/2/2000	4/8/00	Stacy went over flow chart for Deposit Process for ESP Consolidated billing and Deposit Process for UDC consolidated billing. (See attachement to Billing minutes for 2/24/00) 3/8/00 There is no formal Rule requirement dictating deposit refunds for ESP Consolidated billing customers. The current business processes have been identified (see flow) for TEP, SRP and APS. Other UDCs can submit their deposit business processes to theBilling Subcommittee Chairperson. Deposit requirements are to be determined by the individual companies based on their individual credit policies. No further action needed.
57	How will we handle customer bill disputes that are filed with the ACC for ESP Consolidated Billing.	2/8/00	4/19/00	2/8/00 Bill will check at the ACC how often customers file complaints with the ACC for bill disputes. How will UDCs handle the requirement for the ESP to make us whole? Action: Bill to check at the ACC for proposed changes Resolution: The ACC will notify both parties of customer disputes when they are contacted by the customer.
58	How will bill inserts be handled for ESP Consolidated billing as it relates to mandated regulatory messages?	2/8/00	4/19/00	2/8/00 ESPs will not print marketing messages on their bill. In CA, UDCs have to submit their inserts to the CPUC for review. If there is marketing language in the inserts, the UDCs have to remove the language. ESPs also have an opportunity to review all messages prior to distribution to the customer Action: Be prepared to discuss this issue. UDC's determine proces for removing marketing language from mandatory messages. Resolved: TEP will send one mandated message per customer to the ESP for distribution to customer either hard copy or electronically. APS will provide the mandated messages on their web site. They will not put it on the EDI 810

Billing Subcommittee Issues
Unresolved Issues

Issue #	Issue	Date Issie was Identified	Date Issue Resolved	Resolution/Discussion
16	Will ESPs be required to remit charitable contributions? (SHARE/Hero)	Nov 10, 1999	4/19/00	Further discussion on December 3rd Standardization meeting. **<u>Opinions:</u>** New Energy –Does not want to be responsible for tracking and remitting funds back to the UDC for distribution to the charitable organizations. 2/2/2000 APSES agrees with New Energy's position. The ESP is liable for the remitting the pledge amounts to the UDC potentially before the customer actually pays the ESP. Barry Scott SSVEC I believe the entity producing the bill should be responsible for collecting the entire payment. They, in turn, should disburse the money accordingly. It will become a quagmire if each competitive entity only feels a responsibility to collect their piece of the pie. (How will we ever handle delinquents and partial payments?) This does not even consider the resentment the customers will feel about having to send checks to all of these diverse places to make sure their electrical bill is paid. I think this reasoning should apply to charitable programs as well, for example "Operation Roundup". 2/8/00 Who is responsible for the paper-work if the customer wants to remit charitable contributions 3/22/00 Discussion: Action: UDC's determine what their position is, why they do the SHARE program, the implications if they don't do it, and a proposal of how to handle this issue. 4/8/00 Bill Rigsby-Nothing in rules requiring UDC's or ESP's to remit charitable contributions. TEP will only offer charitable contributions for Dual Billing. They will not offer it with ESP Consolidated. APS-will continue to offer it on all billing options and will maintain the "paperwork". Trico-think they would offer it, but need to evaluate this further. New West: flexible as long as they don't have to deal with the "paper work".

43	Is there a regulatory requirement for UDCs to collect and remit charitable contributions to social agencies. Likewise, is there any regulatory requirement for ESP's to participate in collecting or remitting charitable contributions on behalf of an UDC.	2/2/2000	See Issue 16	2/2/2000 There is potential for state funds to be reduced because there potentially is no requirement to continue these programs. Resolution: There is no regulatory requirement in the rules for this issue. However, in some rate cases (because of conditions set for in a settlement agreement) the utilities may be required to reemit charitable contributions. Therefore the ESP and UDC would handle on a case by case basis.

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7	How Rebate/Rebill will be handled?	Oct 26, 1999		Further discussion needed. We need to confirm this as a business decision. Will this be handled as a cancel/rebill or adjustment line item? Once the discussion is complete – this can be translated to the EDI rule. This issue can be raised in the December 3rd Standardization Meeting. UIG – recommends the cancel/rebill scenario. Most UDCs can support the cancel/rebill scenario. The MRSP must post corrected 867s for retrieval by all parties. 3 categories of Billing Adjs. 1. Usage Related (dead meter, bad multiplier, etc.) Cancel/rebill 2. Rate related (incorrect rate calculation) Cancel/rebill 3. Non–usage related (flat rate, tax changes) Misc. Adjustment 2/2/2000 This is still an issue. Another issue to consider, what happens if an ESP or UDC discovers a need to backbill and the customer has switched several times since the original billing took place. Reference ACC rules R14-2-210 section E. See Cancel and rebill discussion document. 3/8/00 Action items: APS will bring a copy of a real 810 showing a cancel rebill and how it is represented in the EDI format. All UDCs need to report on their cancel/rebill thresholds. All participants need to identify some of the business issues in relation to rebate/rebill and misc. adjustments. ESPs will bring real scenarios of their experiences in CA.. 3/22/00 Discussion took place to have a way of communicating specified rebate/rebill information outside of the 810 for the interim. Actions: UDC's to discuss the interim proposal and be prepared to discuss outcome.
62	If back billing is required for period where the customer is both Standard Offer and DA, for ESP Consolidated Billing, the ESPs will want to bill/pay only the DA period	2/8/00	Refer issue #7	3/22/00 Janie to bring California options to next meeting. Action: UDC's to see how can supply intermittent data.
72	How are adjustments going to be handled in the 810.	2/24/00	Refer to issue #7	How will we communicate reason for Misc. adjustments.

15	Does standardization need to allow for Summary Billing - ESP Consolidated Billing?	Nov 10, 1999		Further discussion – UDC would need to pass service periods. Would the UDC un-summarize the customer's bill for ESP Consolidated Billing? **<u>Opinions:</u>** New Energy – The Biller of the end use customer is the entity that should summarize the bill. TEP is not supporting summary billing for Direct Access customers due to cash flow issues. This is suggested in their proposed tariff (Article 24), but they have not been approved. 2/2/2000 APSES – The Biller of the end use customer is the entity should summarize the bill. Barry Scott SSVEC -- I think the entity doing the billing should provide the consolidation. I believe the customers will resist having bills coming from all over the place. In some respects, this would be a step back to go from one bill for electrical service to many.
21	DA Market Issue – for UDC or Dual billing options, will Summary Billing be available for DA customers?	2/2/2000		2/2/2000 TEP will not offer Summary Billing per pending (Article 24) APS feels it is a billers service. If APS is the biller they will offer these services. SRP will offer these services for Dual or UDC Consolidate Billing.
18	For end use customer billing (dual billing situation) the ACC Rules are not specific about the responsibilities of what the utility is obligated to show on their bill and what the ESP is obligated to show on the bill.	2/2/2000		2/2/2000 In many markets (CA specifically) beginning and ending meter reads need not be displayed on a bill. In the Arizona market the utilities are required to show specific pieces of information but it's unclear if the ESPs are required to follow the same rules. This could apply to all revenue cycle services. 2/24/00 Bill Rigsby reported on the ACC Rules. Refer to sections in the ACC Rule R14-2-210B-2 and R14-2-1612. The verbiage states that ALL bills must contain the data elements referred to in these sections. Therefore, UDCs would be required to show a generation line item on their bill (dual billing) showing a zero amount due. Additionally, the ESP would be required to show a CTC charge on their portion of the bill with a zero amount due. Action Items: ESPs and UDCs create a proposal for a short term solution which may require filing for a waiver to the Rules as a short terrn solution. All parties to come up with possible long term changes to the Rules. Issue for MRSPs: Beginning and ending reads must be printed on the bill according to the Rules. Therefore these must be passed to the billing parties. 3/8/00 Should a Rule change be suggested as a short-term solution. It is possible to put this in a combined waiver of issues that need to be changed in the Rules. A long term solution would be actually to change the verbiage. Action Items: ESPs and UDCs should come prepared with their company's position in regards to filing waivers. The group will come up with a proposal about how this issue should be resolved. 3/14/00 It was decided to have a separate waiver filed for this issue (separate from #28,36, & 56) 3/22/00 Proposed Resolution: The bill party needs to itemize the bill components to allow customer to break down/re-calculate the bill.

24	When the UDC estimates the bill in ESP Consolidated billing, an agreed upon process and timeframe needs to be set for troubleshooting before the bill is actually sent to the customer.	2/2/2000		2/2/2000 This is a meter reading to data input billing issue. Examples include the CA model – MADEN Meter and Data Exception Notice. Could be impacted by VEE rule differences, etc. 2/24/00 Janie Mollon is preparing a suggested model for Arizona to report billing and metering exceptions. Janie will send out proposal and suggestions. Members are to look at and send back comments to Janie. (Recommendation, timeline, with your proposed modification.) Janie will compile for next meeting. 3/8/00 The Billing Subcommittee agreed that an exception process such as the MADEN is needed for handling exceptions. The MADEN process will be submitted to the Policy Subcommittee for standardization across all subcommittee exception process. All committee members should review the document in it's entirety and be prepared to discuss implementation issues. Stacy Aguayo will check with CA UDCs to see if more MADEN information is available. Action Item: UDCs need to re-evaluate the time frame of estimation. Is there any flexibility before estimating? What notifications should/are in place for notifying MRSPs of missing data? 3/22/00 take the BEN proposal to our companies and discuss the possibility of implementing this notification process Be prepared to talk about a possible implementation guidelines
20	Can other utility service charges be passed to the ESP for Consolidated Billing (gas, water, sewer, telephone, etc.)	2/2/2000		2/2/2000 This may not be in the scope of the PSWG charge. We are focusing on the transfer of electric information only. This may need to be addressed at a later date.
59	Need clarification on estimating rules specifically section 210-A3-5	2/8/00		2/8/00 Confusion about the load profiled customer or customers needing load data. Does this have anything to do with real time pricing?
60	According to the rules, a third party can be back billed up to 12 months. What will the process be for back-billing third parties? (R14-21-E3)	2/8/00		2/22/00 According to the rules, there are specifics on how utilities bill a 3rd party but there is no specification for any other market participants. (R14-2-210-E3)
63	If UDC or ESP charges are not transmitted by the drop dead date/time, what is the responsibility of the biller to include language on the bill advising the customer of missing charges.	2/8/00		

Metering Systems and Meter Reading Subcommittee Issues

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
25	What specific VEE rules should utilities use on an ongoing basis to verify and bill off of incoming MRSP reads.	1/26/00		1/26/00 - Since MRSPs use different algorithms, it's difficult for utilities to determine if MRSPs are performing VEE on an ongoing basis. If the utilities use their own VEE systems to verify reads it may cause invalid rejections. 2/1/00 – What is the utilities responsibility to audit the MRSPs? The rules state this certification must take place yearly. 4/27/00 A sub/subgroup was formed to review the existing VEE rules, develop objectives, changes and proposals (if needed), develop performance measures and monitoring criteria. TEP (Tony Gillooly), APSES, New West Energy (Janie Mollon), C3 Comm, CSC, APS, SRP (Greg Carrel), a representative from the coop (possibly Barry Scott), and possibly First Point. Renee Castillo volunteered to chair this sub/subgroup and will set up a meeting with these participants.	Meter Systems and Meter Reading Subcommittee	Pending

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
33	For access to a meter, some UDCs require the ESP to get keys, combos, etc. from the customer. In many cases, the customer does not have the key.	1/27/00		2/3/00 APS is not going to provide keys to the MSP. They would like the MSP to get the key from the customer. Issues: Customers may not have keys. Utility keys may not be able to be duplicated. Or utilities may want to offer a dual locking device on a contractual basis with utilities and MSPs. New West Energy – This is a barrier to getting access to change meters for customers to go DA. <u>Suggestion</u> - If the customer is releasing their customer data (historical) anyhow, could the key process be incorporated in the release? **<u>Action Item:</u>** All Utilities need to research what their key policy is and report to subcommittee by 2/16/00. Janie Mollon will bring CA access process. Per Jamie – Schlumberger – In the case of customer's lock, they are just cutting the lock and then supplying a new lock to the customer. The customer is then responsible for getting a key to the UDC fof access to the site. Per Marv Buck – CUBR is suggesting that the UDCs change customer supplied locks with UDC supplied locks. Then the UDC retains possession of the master key and they can supply the customer with slave keys for them to get to the MSP and ESP. Pending Resolution: For customer supplied locks, the MSP will cut the lock, if applicable, and supply the customer with a new lock and keys. It is the customer's responsibility to get the new key to the UDC. The MSP will communicate access changes back to the UDC on the MIRN form in the remarks section. CUC Comments: The UDC requires access to metering equip on the custs premises for safety reasons and already have keys that were supplied to the customer. The ESP should be responsible for supplying the UDC with a key to any lock changed on the customer's metering room. It is not reasonable to require the customer to produce another key for the UDC.	Meter Systems and Meter Reading Subcommittee Priority #1 MSP and MRSP issue	Pending
33 Con't	For access to a meter, some UDCs require the ESP to get keys, combos, etc. from the customer. In many cases, the customer does not have the key.	1/27/00		New Proposal: For customer supplied locks, the MSP will cut the lock, if applicable, and supply the customer with a new lock and keys. The MSP will place a dual hasp on with the customer's lock and then seal up the other hole on the hasp. This will be indicated on MIRN form for the UDC to replace the seal with an UDC lock. If the MSP cuts a UDC lock, they will replace it with a dual hasp with a new customer lock and a seal where the UDC lock will be placed. This will be noted on the MIRN form and the UDC will replace the seal in their normal course of business.		Pending
35	At what point does an ESP take responsibility on a meter exchange? And who is responsible for energy consumption during the exchange?	1/27/00		2/3/00 **<u>Action Items</u>:** Utilities need to report on their processes on 2/16/00. Pending Resolution: The time in which the ESP takes responsibility depends on the switch procedures in the separate UDC territories.	Meter Systems and Meter Reading Subcommittee Priority #1	Pending Resolution 5/18/00

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
37	Load research meters- Are the UDCs intending have to a dual meter installed or are they going to pick another sample customer when the customer goes DA? Also, will the UDCs allow the ESPs to use existing phone line for to read the meter for DA purposes? Or vice versa…..can the UDC use ESP phone lines?	1/27/00		2/3/00 **<u>Action Items:</u>** Utilities to document and report what the process will be for handling Load Research meter by 2/16/00. 2/16/00 SRP will choose new sample. In most cases phone line is owned by the customer APS will choose new sample. In a few cases they will remove their existing phone line. 4/27/00 Please refer to the UDC Business Rule Comparison to be included with the PSWG report to the Commission.	Meter Systems and Meter Reading Subcommittee Priority #1	Pending Resolution 5/18/00
39	Do the DA meters installed have to have a visual display? Why? This limits the equipment types that can be installed?	1/27/00		2/3/00 The TR Recorder does not have a display. The requirement came from a EUSERC. **<u>Action Items:</u>** Utilities need to report on their needs for the display by 2/16/00. Jeanine/APS will check with the EUSERC requirements. ESPs will report on what impacts this requirement could have in their orgs. According to ANSI a displayed is not 'required'. Further discussion is needed. Metering boxes are the way the technology is moving….therefore no display. This may be a customer issue. Utilities to report on why a display is needed. Darrel Pichoff to check with RUCO to see if there's a requirement. 3/2/00 Per Prem Bahl of RUCO: RUCO's position is: there must be a visual display on all electric meters for residential consumers. The consumer must be able to read the kWh and kW readings. RUCO will insist on this. K.R. Saline represents 24 Irrigation Districts, Electrical Districts, and Municipalities. KRS will insist on visual displays on electric meters for both residential and commercial customers. 4/27/00 This is to be addressed in an upcoming meeting since this issue is currently happening in production today.	Meter Systems and Meter Reading Subcommittee Priority #1	Pending
40	What are the UDCs processes for scheduling MSP work? What if an MSP picks a date to remove and install a meter and the schedule must be changed? How are these exceptions handled?	1/27/00		2/3/00 This issue may be addressed when we start to review the data elements. The utilities must be able to speak to the schedules on metering. 4/27/00 The MDCR and procedures address this issue. See UDC Business Rul Comparison document.	Meter Systems and Meter Reading Subcommittee Priority #1	Pending Resolution 5/18/00

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
41	Who is responsible for validating that a meter can be read after a MSP has set a new meter?	1/27/00		1/27/00 In CA, it's a requirement from CPUC (Rule 22), the ESP is responsible for ensuring that the newly installed meter can be read prior to 1st billing by the MRSP or face penalties. 2/3/00 Per 1st Point – This is usually done at the meter install time. 4/27/00 This will be addressed in the VEE sub/subgroup.	Meter Systems and Meter Reading Subcommittee Priority #3	Pending
45	Standardization data content, data format and data transmission is needed for Metering Data.	2/3/00		2/3/00 Fax and email are not acceptable forms of data transmission. Trading Partners are not able to populate their databases. 4/27/00 The subgroup has standardized the data content, the data format and a basic transmission method (email with Excel spreadsheet). Additional electronic methods will be explored.	Meter Systems and Meter Reading Subcommittee	Pending Resolution 5/18/00
53	ISSUE: Blackout period for Direct Access meter exchanges is too long and is not consistent between UDCs.	1/25/00		Currently, the 3 largest UDCs require that meters that need to be exchanged for Direct Access service cannot be exchanged for a period of time around the current meter's read date. The length of time varies by UDC, but extends up to approximately 9 working days for one UDC. This requirement is problematic for ESPs and MSPs because it effectively allows meters to be exchanged during only half of the month for each account (9 working days equates to approximately half of a calendar month). When a customer has multiple accounts on multiple read cycles that all require meter exchanges, the MSP must plan their installation schedule around the UDC blackout period. This makes it virtually impossible to exchange multiple meters on consecutive days during the month. Since most certified MSPs are installing meters with out-of-state personnel, this requirement adds to the cost of meter exchanges for MSPs and ultimately for ESPs and customers. RECOMMENDATION: The Metering Working Group should examine the process for meter exchanges and shorten or eliminate the blackout period requirement. The group should look at best practices in other states where blackout periods have been eliminated or greatly reduced to foster a more efficient competitive market. Where possible, the blackout periods should be consistent across the UDCs in the state. Suggestion from Janie Mollon – NWE: To switch a customer MSP could not install a meter 5 workdays before a read date or 2 workdays after a read date. The actual switch happens on the read date. 3/16/00 Jim Wontor APSES brought another proposal. Eliminate blackout periods and allow customer's to switch on exchange date. Action Item: The ESPs will consolidate their proposals for a best practice suggestion on 3/30/00. 4/27/00 SEE the ESP Hybrid proposal addressing switch dates and blackout windows. Also, see the UDC Response to Provider Hybrid Proposal.	Metering Subcommittee Priority #1	Pending

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
53 Con't	Blackout period for Direct Access meter exchanges is too long and is not consistent between UDCs.	1/25/00		Consensus was not reached between TEP, SRP and APS, APS operates currently without a blackout window even though their Schedule 10 allows for a blackout window. SRP does not operate without a blackout window. TEP operates with a 5 wkday blackout window. Action Items: APS need to find out how long they are willing to work without for 6 mos. a blackout window. TEP will check with their staff to see if they will work with the 5 wkday blackout window and then reevaluate in 6 mos. Navopache (Dennis Hughes) would agree to work with the 5 wkday blackout window with the agreement to reevaluate any market impacts after 6 months. Trico – (Anne Cobb) They certainly see advantages to having a blackout period. They would agree to work with the blackout window with the agreement to reevaluate any market impacts after 6 months.		Pending
65	The Arizona 867requires the MRSPs or UDCs to pass billing reads. Is this necessary? Could the Interval data only be passed? Then the UDC/ESP would be responsible for creating the billing reads. Determine if the read will be encoded or calculated.	2/17/00		Action: Confirm that it is a requirement to have both beginning and ending reads. Yes this is a requirement. 3/16/00 Per APS – Joe Webster, They need both the interval and billing reads. This is used for the VEE process. They would need reads off of the register (encoded), not calculated reads. Per SRP – Greg Carrel – on interval data accounts, they bill off of the interval data only. The interval data is VEEd on the interval data. Per Navapache – Dennis Hughes – They have approx 7,000 interval data accounts. However, they bill off of the billing reads. Per TEP – On very select occasions, they will bill off of IDR data. However, they will validate on the billing reads. Action Item: A small subcommittee will review possible solutions to this issue: Marv Buck, Janie Mollon, Tim Jones, Kimane Aycock, Joe Webster, Darrell Shear, Greg Carrel, and reps from TEP. They will report back to Metering Subcommittee on 4/13/00. 4/27/00 See the UDC/ESP Proposal. CUC sent comments that their company does not support this proposal. Dennis Hughes reported that AEPCO does not support this proposal. The subgroup took a vote to bring the issue up to the large PSWG meeting and only 2/3 majority was reached. The subgroup decided that further discussion was needed. Renee Castillo and Marv Buck will develop a memo to be sent out to the large PSWG. We will set aside 1 hour of discussion to take place immediately after the PSWG meeting on 5/3/00 at the Mesa Conference Center. All market participants are encouraged to attend the discussion.	Metering Subcommittee Priority #1	Pending

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
66	How are the UDCs identifying the master meter and then showing subsequent sub-meters? Is there a common way to identify the meters with the same address with multiple meters? Currently the UDC issues one MI form per meter.	2/17/00		Action: Identify how the UDCs are handing totalized metering and sites with multiple meters. 4/27/00 This is identified on the new EMI forms.	Metering Subcommittee Priority #3	Pending Resolution 5/18/00
67	If a master metered account goes DA, does the ESP lose grandfathered agreements to continue with the master metering?	2/17/00		This is an action item for the UDCs. Dave Rumolo will research FERC requirements. 4/27/00 Dennis Hughes to follow up with Dave to check and see what the status is of this issue.	Metering Subcommittee Priority #3	Pending
68	Site Meets – What are the UDCs policies?	2/17/00		This will be added to the Business Rule Document. The UDC policies and procedures have been added to the Business Rule Comparison Document.	Metering Subcommittee Priority #1	Resolved
64	How many decimal places should be required before applying the multiplier to a demand read? How many decimal places should be required for billing demand? Issue: In the 867, when we convert the kW back to a read how many decimals places need to be accommodated? **Issue: Do we want the MRSP to give us usage/multiplier or give us the actual read (w/ two decimal places)?**	2/16/00	4/13/00 mtg of metering sub committee 2 decimal places	**Action:** Can CIS multipliers be changed to "one" since the MRSP is adding in the multiplier to the demand provided in the 867. Review the 867 guideline to determine if the billing demand posted should have the multiplier applied to it. – The MSP is required to apply the multiplier to the demand. Action Item: Utilities need to research when a demand figure is received from an MRSP, what is their process for backing out the multiplier and extracting the read. Considerations: Decimal points accommodated and having different multipliers for demand meters in the CIS systems. Action: Check 867 requirements to ensure we are all on the same page. Check for all issues pertaining to the 867 (issue #64, #46, & #65) 3/16/00 What is happening on the MRSP reads, the reads are coming with inconsistent . Some are coming with 1 decimal place, while others are being shown with up to 4 decimal places. The problem is that the UDCs take demand reads up to 2 decimal places. Anu more than 2 decimal places are either truncated or rounded by the UDCs in order to bill. This could cause the demand calculation to be off from what the other party would be billing. Possible Solution: The MRSP can deliver the read rounding to 2 decimal places. Or the demand be figured on the interval data only. Both the ESP and the UDC would have to bill of of the same value (kW figured on read or interval data) to ensure the same billing kW figure. Currently the ESPs are not billing on demand. This will be come a when they decide to start billing the demand. If they were to bill off of the demand, they would extract it from the interval data. Although the read would still need to be supplied for VEE. Action Item: The participants need to go back to their companies to see if they can handle kW reads to 2 decimal places. Are the porties willing to say that this would be the standard. CUC comments – Their system is not set up to bill multpliers already applied. This will cause manual work on our billing staff and potentially result in billing errors.	Metering Group Priority #1	Resolved

Issue #	Issue	Date Issue was Identified	Date Issue Resolved	Discussion	Group Assignment	Status
71	**If after receiving an RQ DASR and the UDC is planning to disconnect for non-payment or l turn off a customer prior to the switch, what is the process to notify the ESP that the customer will be disconnected.**	2/24/00		Defining Issue: This particular issue focuses more on how the metering side is handled when this type of issue arises. How to stop the meter exchange process. 4/27/00 This will be reviewed when additional business processes are reviewed.	Metering Group Priority #3	Pending

Cooperative Response to the PSWG Master Issues List - DRAFT

The Cooperatives understand that Staff and the PSWG are in a situation in which there are very tight time deadlines to resolve a large volume of issues related to the implementation of competition. The Cooperatives also understand that this situation makes it necessary to have many subcommittees holding many meetings almost everyday. The Cooperatives, however, because of their small staffs and far travel distances from Phoenix, (unlike APS and SRP who have very large staffs and are located in Phoenix) are concerned that the shear magnitude of these meetings violates the second stated goal of the PSWG, which is that "There will be complete and total participation and involvement from everyone." This also creates a situation where the Cooperatives are constantly reacting to the results reported by the PSWG subcommittees, and places a delay on the Cooperatives' management from committing to these results for fear of not having the time to thoroughly think things through. Accordingly, the Cooperatives request that the PSWG collectively think of solutions to help the Cooperatives reach full participation in this important process and that any solution be implemented expeditiously before the PSWG process progresses too far.

BILLING ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
1	Tax Exempt: Does the ESP currently get Tax Exempt status on 810? Is the ESP required to have certificates for existing exempt customers?	PSWG Resolution as of 2/2/00: It is the end use customer responsibility to provide tax exemption status to each of their providers. The Cooperative's support the PSWG resolution.
2	Credit/Debit Amount by record	PSWG Resolution as of 2/2/00: This will be added to the Implementation Guide as an optional code. The Cooperative's support the PSWG position.
3	Balance (BAL) vs. Total monetary value summary (TDS) for invoice payment. Issue for UDC, they cannot bill past due charges, since they may not be aware of payment amounts and dates.	PSWG Resolution as of 2/2/00: UDC will not send payment information to the ESP since the ESP is covering the customer's receivable to the UDC. The Cooperative's support the PSWG position.
4	Invoice Start & End Date do we need to state on bill?	PSWG Resolution as of 2/2/00: Both parties shall disclose this information. The Cooperative's support the PSWG position.
7	How Rebate/Rebill will be handled?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing. The cooperatives believe they should be able to maintain current individual company policies and procedures based on the systems in place.
8	UDC Information - Does the UDC have to pass the contact information address, etc. on each transaction – including the ACC phone number?	PSWG Resolution as of 2/24/00: As of 2/24/00, the UDC's will make available to the PSWG a consolidated list of UDC Emergency Contact Numbers. It will be the responsibility of the UDC's to communicate to subsequent ESP's the UDC Contact Number and ACC

		dispute number at the time of execution of the ESP service agreement. As a long-term solution, the UDC will provide the UDC emergency contact numbers and the ACC number to the ESP at the time of certification with the UDC. The Cooperative's support the PSWG position.
9	Are tables graphs applicable this yr/last yr/last month?	PSWG Resolution as of 2/24/00: The 810 will not have a place to pass last months/last years consumption for the ESP to place in a table. The Cooperative's support the PSWG position.

BILLING ISSUES

ISSUE	ISSUE DESCRIPTION UE DESCRIPTION	COOPERATIVE PERSPECTIVE
10	Business, Regulatory Notices and advertising messages how we would handle? What would be the size (# of lines) and content and placement on the bill? For instance: disconnect notices, Levelized changes, capital credits. How do we anticipate handling non regulatory messages on the bill	PSWG Resolution as of 3/8/00: The UDC will pass the ACC or Legislated mandatory/regulatory message with the customer's bill data. This will transmit via the normal billing process agreed upon between the UDC and ESP. The ESP is required to print the message on the UDC portion of the consolidated bill. Advertising or business messages will not be passed by the UDC to the ESP for printing on the bill. For Cooperative's who may wish to use ESP consolidated billing it is our position that notices which are required by the Cooperative by-laws (such as notice of annual meetings, by-law changes, capital credit allocations, etc) should also be included as "regulatory messages". It should be noted that with Cooperatives the consumer is an owner of the Cooperative and the Cooperative is required to send this information. If this option is not provided, then the members of the Cooperative are left with the added expenditure of multiple mailing cost.
11	Will ESPs want to partake in SurePay? (Debit ESPs Bank Account for monies owed to the UDC)	PSWG Resolution as of 2/2/00. If this is done, it should be based on a contractual agreement between the ESP and the UDC. The Cooperative's support the PSWG position.
12	3rd party Billing (Should UDC continue to offer?)	PSWG Resolution as of 2/2/00. This is an arrangement that will need to be made between the biller (in the case the ESP) and their customer. The Cooperative's support the PSWG position.
13	Payment Date appearing on customer's bill.	PSWG Resolution as of 2/2/00. Payment date, payment amount and payment received date will not be passed to the ESP on the 810 for printing on an ESP consolidated bill. The Cooperative's support the PSWG position.
14	Transmission Charge should it be displayed on the bill?	PSWG Resolution as of 2/2/00. Any transmission charge identified as an end use customer charge will be included in the UDC portion of the bill. All other charges will be settled with the Scheduling Coordinator. The Cooperative's support the PSWG position.
15	Does standardization need to allow for Summary Billing - ESP Consolidated Billing?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
21	DA Market Issue – for UDC or Dual billing options, will Summary Billing be available for DA customers?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

BILLING ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
16	Will ESPs be required to remit charitable contributions? (SHARE/Hero)	This issue is still pending The Cooperative's perspective is that if the charitable contribution is a required service to be provided to the consumer/member, then the ESP should be required to collect the contributions. Multiple mailings and processing result in higher cost for the member of the Cooperative.
43	Is there a regulatory requirement for UDCs to collect and remit charitable contributions to social agencies, Likewise, is there any regulatory requirement for ESPs to participate in collecting or remitting charitable contributions on behalf of a UDC.	This issue is still pending. The Cooperative's perspective is that if the charitable contribution is a required service to be provided to the consumer/member, then the ESP should be required to collect the contributions. Multiple mailings and processing result in higher cost for the member of the Cooperative.
17	Will the ESPs support levelized UDC billing line items?	PSWG Resolution as of 2/24/00: The ESP has the option to offer levelized billing to the end use customer. The UDC will not pass levelized billing line items for ESP Consolidated billing. The Cooperative's support the PSWG position.
18	For end use customer billing (dual billing situation), the ACC rules are not specific about the responsibilities of what the utility is obligated to show on the bill and what the ESP is required to show on the bill.	This issue is still pending. The Cooperatives perspective is that in a dual billing situation, the Cooperative should only be required to include the components that the Cooperative is responsible and is billing for.
19	Once the troubleshooting process has taken place, and the UDC is estimating (an MRSP did not deliver the data in a timely manner or the read could not be retrieved), should the UDC transmit the estimation reasons for the ESP Consolidated Bill.	PSWG Resolution as of 4/6/00: A reason code to reflect the message "Meter Data not available". The Cooperative's support the PSWG position.
24	When the UDC estimates the bill in ESP Consolidated billing, an agreed upon process and timeframe needs to be set for troubleshooting before the bill is actually sent to the customer.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
5	Reason of Estimate - Do both parties need to give?	PSWG Resolution as of 2/2/00: It is the billers responsibility to print this in the bill using the 867 standard estimation reason codes. The Cooperative's support the PSWG position.
20	Can other utility service charges be passed to the ESP for Consolidated Billing (gas, water, sewer, telephone, etc.)?	PSWG Resolution as of 2/2/00: This may not be in the scope of the PSWG charge. We are focusing in the transfer of electric information only. The Cooperative's support the PSWG position.

BILLING ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
6	Should non-utility charges be included on ESP consolidated bills?	PSWG Resolution as of 2/2/00: UDC cannot pass charges for non-utility related charges for printing on an ESP Consolidated Bill. The Cooperative's support the PSWG position. This issue is another example of the concern Cooperatives have due to possible requirements that may lead to increased infrastructure and labor cost to our members.
22	If a customer has a credit or debit balance on the bill when they switch to DA, is the utility obligated to refund that money?	PSWG Resolution as of 3/8/00: At the time the customer goes DA and the customer has a debit balance, it will be the sole responsibility of the UDC to collect the money from the customer. The Cooperative's support the PSWG position.
23	If the utility is holding a deposit for the customer and the customer switches to ESP consolidated billing, is the utility required to refund the entire deposit since the receivable is paid to the UDC by the ESP?	PSWG Resolution as of 3/8/00: Deposit requirements are to be determined be the individual companies based on their individual credit policies. The Cooperative's support the PSWG position.
57	How will we handle customer bill disputes that are filed with the ACC for ESP Consolidated Billing?	PSWG Resolution as of 4/19/00: The ACC will notify both parties of customer disputes when they are contacted by the customer. The Cooperative's support the PSWG position.
58	How will bill inserts be handled for ESP Consolidated billing as it relates to mandated regulatory messages?	This issue is still pending. For Cooperative's who may wish to use ESP consolidated billing it is our position that notices which are required by the Cooperative by-laws (such as notice of annual meetings, by-law changes, capital credit allocations, etc) should also be included as "regulatory messages". It should be noted that with Cooperatives the consumer is an owner of the Cooperative and the Cooperative is required to send this information. If this option is not provided, then the members of the Cooperative are left with the added expenditure of multiple mailing cost.
59	Need clarification on estimating rules specifically section 210-A3-5.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
60	According to the rules, a third party can be back billed up to 12 months. What will the process be for back-billing third parties? (R14-21-E3)	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
62	If back billing is required for period where the customer is both Standard Offer and DA, for ESP Consolidated Billing, the ESPs will want to bill/pay only the DA period.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

BILLING ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
63	If UDC or ESP charges are not transmitted by the drop-dead date/time, what is the responsibility of the biller to include language on the bill advising the customer of missing charges?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
72	How are adjustments going to be handled in the 810?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

REMITTANCE & TRANSACTION ERROR ISSUES (To be addressed after the June 15 report)

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
30	Do We need to prioritize transactions by importance due to financial considerations and customer service (for problem resolution and cycle time of EDI 824)?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
31	Is there a need to standardize dual path or single path when handling the 820? Do we provide a remittance advice directly to the ESP and payment directly to the bank (dual path)? OR do both documents go directly to the bank? (single path)	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
42	Will we require an 824 on all transactions (accepted or taken exception to a data element)? Do we only want to get an 824 when there's a problem with data?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

DASR/ENROLLMENT ISSUES (To be addressed after the June 15 report)

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
49	Develop interim business processes that can be implemented manually, and plan mapping for both out-bound (UDC to ESP) and in bound (ESP to UDC) DASRs for the following communications. The business processes should be implemented immediately by each UDC with as much consistency as possible, and EDI mapping can be phased in Customer Moving: - Notification of direct access customer moving to new address within the same distribution company territory without having to return to bundled service	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
50	Develop interim business processes that can be implemented manually, and plan mapping for both out-bound (UDC to ESP) and in-bound (ESP to UDC)	This issue is still pending. The Cooperatives will support a resolution that is not

	DASRs for the following communications. The business processes should be implemented immediately by each UDC with as much consistency as possible, and EDI mapping can be phased in. New Customer - Same Facility: - A new customer takes over an existing direct access facility, keeps same ESP and meter without returning to bundled service.	cost prohibitive due to system infrastructure requirements or labor intensive processing.
51	Develop interim business processes that can be implemented manually, and plan mapping for both out-bound (UDC to ESP) and in-bound (ESP to UDC) DASRs for the following communications. The business processes should be implemented immediately by each UDC with as much consistency as possible, and EDI mapping can be phased in. "Account Update" - Notification of changed account information. The UC and PD DASRs appear to be both in/out-bound in the Arizona DASR Handbook.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
75	On the incoming DASR – only kWh meter number is required. The state DASR handbook does not accommodate a kWh meter and Kvar meters, or other metering combinations.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
76	On the DASR – the forecasted meter owner is a required field. Is this appropriate? Should this be taken off of the RQ DASR?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

METERING SYSTEM AND METER READING ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
25	What specific VEE rules should utilities use on an ongoing basis to verify and bill off of incoming MRSP reads?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
33	For access to a meter, some UDCs require the ESP to get keys, combos, etc. from the customer. In many cases, the customer does not have the key.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
35	At what point does an ESP take responsibility on a meter exchange? And who is responsible for energy consumption during the exchange?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
37	Load research meters - Are the UDCs intending to have a dual meter installed or are they going to pick another sample customer when the customer goes DA? Also, will the UDCs allow the ESPs to use existing phone line to read the meter for DA purposes? Or vice versa……can the UDC use ESPs phone lines?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
39	Do the DA meters installed have to have a visual	This issue is still pending.

	display? Why? This limits the equipment types that can be installed?	The Cooperatives believe that the meter should have a visual display. Our members should have the ability to verify their own usage. The UDC should also have the ability to verify the readings.
40	What are the UDCs processes for scheduling MSP work? What if an MSP picks a date to remove and install a meter and the schedule must be changed? How are these exceptions handled?	This issue is still pending. The Cooperatives support a 5 day black out period for a 6 month trial period.
41	Who is responsible for validating that a meter can be read after a MSP has set a new meter?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
45	Standardization data content, data format and data transmission is needed for Metering Data.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing. It should be noted that EDI system requirements are costly. It is the position of the Cooperatives that the ESP's should be responsible for the certification cost since the UDC does not derive any benefit from the process. The Cooperative's Standard Offer members should not be responsible for direct access cost.
53	ISSUE: Blackout period for Direct Access meter exchanges is too long and is not consistent between UDCs.	This issue is still pending an ESP hybrid meter exchange proposal. The Cooperatives support a 5 day black out period for a 6 month trial period.
65	The Arizona 867 requires the MRSPs or UDCs to pass billing reads. Is this necessary? Could the Interval data only be passed? Then the UDC/ESP would be responsible for creating the billing reads. Determine if the read will be encoded or calculated.	This issue is still pending. The Cooperatives need the actual reads for proper verification of our members usage. This read should be encoded, not calculated.
66	How are the UDCs identifying the master meter and then showing subsequent sub-meters? Is there a common way to identify the meters with the same address with multiple meters? Currently the UDC issues one MI form per meter.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
67	If a master metered account goes DA, does the ESP lose grandfathered agreements to continue with the master metering.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
68	Site Meets -- What are the UDCs policies?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing. Note that these issues are being addressed in appendix M-7 of the UDC business rule comparison document.
64	How many decimal places should be required before applying the multiplier to a demand read? How many decimal places should be required for billing demand?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

	Issue: In the 867, when we convert the kW back to a read how many decimal places need to be accommodated? Issue: Do we want the MRSP to give us usage/multiplier or give us the actual read (w/ two decimal places)?	
71	If after receiving an RQ DASR and the UDC is planning to disconnect for non-payment or I turn off a customer prior to the switch, what is the process to notify the ESP that the customer will be disconnected?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.

POLICY ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
26	XML versus EDI What is XML? Should this be considered for a best practice for the Arizona's model?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
27	Companies are defining ‘workdays' for time frames for work to be completed. The problem is that some companies are including holidays that are not recognized by others. Need to define ‘standardized workday’. Suggested Resolution: NERC holidays recognized but modified. If a NERC holiday falls on a Saturday it is recognized on a Friday and if the holiday falls on a Sunday it is recognized on a Monday. <u>Standardized Work Days:;</u> <u>Any day except Saturday/Sunday or NERC holiday. If holiday falls on a Saturday it is recognized on a Friday,. If the holiday falls on a Sunday, it is recognized on a</u> <u>Monday.</u>	PSWG Resolution as of 2/29/00: NERC holidays recognized but modified. If a NERC holiday falls on a Saturday it is recognized on a Friday and if the holiday falls on a Sunday, it is recognized on a Monday. The Cooperative’s support the PSWG position.
29	Are 997s required for all transactions? Is that going to be our recommendation for the Arizona standards?	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing.
32	What is the true costs of CT/VT (PT) if an ESP wants to buy the equipment? Cost to replace equipment at today's market price OR cost to UDC and depreciated by years since installation.	This issue is still pending. The Cooperatives position is that Replacement Cost should be the standard.
44	Clarify ownership of CT and VTs (PT) based on voltage level.	This issue is still pending. It is the Cooperatives position that the existing ownership language should stand. Added to this it is the belief of the Cooperatives that Primary Transformer ownership should stay with the UDC.
54	Ownership of Current Transformers (CTs) and Voltage	This issue is still pending.

	Transformers (VTs formerly known as PTs) is not consistent across UDCs.	It is the position of the Cooperatives that the existing ownership language should stand.
34	There is no formalized process to report meter exceptions between UDCs and ESPs. (Examples: agreement metering programming, if MI/MAC forms are not completely filled out, etc. See MADEN for details on exception reasons.)	PSWG Resolution as of 3/28/00: It has been agreed that a formal communication method (similar to MADEN) will be utilized. The details of what data elements/guidelines will be discussed in both the metering and billing subcommittees. The Cooperative's support the PSWG position.

POLICY ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
52	UDCs and market participants need a clearly-defined communication process for promptly communicating and resolving problems with data, meters, or bills among ESPs, MSPs, MRSPs, and the UDCs.	PSWG Resolution as of 3/28/00: It has been agreed that a formal communication method (similar to MADEN) will be utilized. The details of what data elements/guidelines will be discussed in both the metering and billing subcommittees. The Cooperative's support the PSWG position.
38	Will the UDCs allow ESPs to interrogate meters on non-DA customers for load research purposes/billing option purposes?	This issue is still pending. Cooperatives are opposed to this. If an ESP wants the data, they should get it from the consumer. Consumer's may be charged a reasonable fee due to the costs associated with gathering the data.
46	All Arizona EDI (DASRs, 867, 810, 650) should utilize GMT for the business transactions and local time for the enveloping. To avoid problems and unnecessary costs to conform to national standardization in the future, standard time references should be implemented immediately by each UDC, and EDI mapping can be phased in.	PSWG resolution as of 4/25/00: All Arizona EDI's should utilize GMT for the business transactions and local time for the enveloping. The Cooperative's support the PSWG position.
47	Standardization of Billing Options (ESP and UDC consolidated billing as well as Dual billing) from all UDCs should be implemented immediately to provide customer choice. Include related changes or impacts to other processes or procedures.	This issue is still pending. The Cooperatives will support a resolution that is not cost prohibitive due to system infrastructure requirements or labor intensive processing. There is a concern that required standardization will result in excessive infrastructure cost to our members.
48	For all Billing and Metering data, UDCs should employ the same rule and/or formula for rounding up data and rounding in calculations. The business process should be implemented immediately by each UDC. Include related changes or impacts to other processes or procedures. Resolution: No Standardization needed.	PSWG resolution as of 2/29/00: No standardization is needed. The Cooperative's support the PSWG position.
55	UDC Fees for Direct Access services (CISR, DASR, metering, meter reading, billing, settlement, etc.) are too high and not consistent between UDCs.	This issue is still pending. Cooperatives do not agree with issue as stated. Each UDC has its own cost structure and circumstances that should be reflected in charges. This should be a reality of doing business for the ESP.
56	Non-availability of local alternatives for providing competitively priced metering services.	This issue is still pending. As the rules are currently written, this is not a Cooperative issue.
28	Clarification on when an UDC can be an MSP. Both sets of Direct Access rules have different definitions. (ACC Rules and HB 2663)	This issue is still pending. As the rules are currently written, this is not a Cooperative issue.

POLICY ISSUES

ISSUE	ISSUE DESCRIPTION	COOPERATIVE PERSPECTIVE
36	ACC Rules Question: Can the UDC provide metering and installation services for DA customer? Short term and after January 1, 2000?	This issue is still pending. As the rules are currently written, this is not a Cooperative issue.
61	Who is responsible for tracking the performance of MSP and MRSP's? What is the process for communicating this information?	This issue is still pending. The Cooperatives believe that this is a function of the ACC.
69	What is the enforceability of the recommended processes or rules of non-ACC jurisdictional entities?	This issue is still pending. As the rules are currently written, this is not a Cooperative issue.
70	A utility can back-bill a 3rd party (if the 3rd party is at fault) up to 12 months (R14-212-/e3). This is only specific to the utility. Should the rule be applicable to other participants other than just the utility?	This issue is still pending. As the rules are currently written, this is not a Cooperative issue.
73	Is NERC using Standard Central Time in Non-EDI transactions? Why is NERC using Standard Central Time and should we be using it?	Yes, NERC is using Central Standard Time. Refer to issue #46 on GMT time.
74	Navopache will be submitting a report to the PSWG regarding what their business processes will be for DA.	The Cooperatives statewide will respond to the PSWG. This report is part of our response.
77	The UMI was presumed to be the national standard for identifying a single meter. However, it’s not being used by any other state in the deregulated market. Furthermore most of EDI documents are not implementing a UMI number	PSWG Resolution as of 3/28/00: Request that the Utilities Director remove the requirement of using the UMI standard from the 5/1/99 report. The Cooperative’s support the PSWG position.
78	There is no language in the rules keeping the MSP from contracting directly with the customers. How should this issue be addressed?	This issue is still pending. The Cooperatives position is that open competition mandates customer choice and the rules as it currently exists support this.

Policy Subcommittee
Appendix Documents

Advantages of XML for EDI

White Paper

November 15, 1999

Cognizant
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Advantages of XML for EDI

Present Situation

Electronic Data Interchange (EDI) has been in use for a quarter century. Despite the long history and numerous advantages of EDI, only an estimated 125,000 organizations worldwide have an EDI system. Furthermore, there are only 80,000 EDI enabled businesses in the US. That works out to less than 2% of the 6.2 million businesses registered in the United States. Due to cost and complexity, small and medium sized businesses find it difficult to implement and maintain a traditional EDI system. For these reasons, most businesses do not enjoy the operating efficiencies that an automated electronic information routing system promises.

The obstacles that businesses must overcome to implement their EDI/EC solutions seem insurmountable, but that is changing. With the advent of XML/EDI, companies can use current standards and existing technologies to enable a simple and meaningful electronic information routing process.

Problems with Traditional EDI

The high cost of implementation and the slow rate of message definition creation have contributed to low adoption levels. Furthermore, EDI has failed to deliver on its vision to remove paper from the trading process. Though EDI has a number of strong points, it also has certain weak areas. Setting up traditional EDI is expensive and time consuming. Trading partners have to synchronize their internal systems with the systems of the partners. This can be a big problem if there are a large number of partners. A change in the format or a new partner means that the translation program needs to be changed. The traditional system does not support versioning. Furthermore, it supports only the data and structure. No support for process and information exchange is available.

XML is being proposed to overcome many of these problems and extend EDI. XML promises to deliver EDI as an alternate technology.

XML and EDI

The answer to improving EDI lies in developing a new paradigm for business data exchanges, combining the promise of XML with the lessons learned from EDI. XML can also build on the 30 years of EDI rather than “reinvent the wheel.”

An EDI application for XML provides the structural complexity that supports and parallels today's EDI transaction sets. XML provides a rich document structure that can be nested to any level of complexity. With XML, documents are like chameleons, capable of being processed by different components, delivered by different mechanisms, and displayed to the user in different ways. It has been envisaged that XML can be used as a "carrier" for the document information so that the transaction can carry not only data (like traditional EDI), but also code (at each level in the transaction tree).

The logical structure of the document and tag set can be specified in a Document Type Definition or DTD. (The best-known example of a DTD is HTML, which is defined by a DTD describing the structure of HTML documents.) In a DTD, sets of elements and their attributes are defined; the names that are used as tags are assigned; and the element relationships or transaction is defined. If a DTD is used, then programs can validate the transaction's structure. One can validate the structure of an XML/EDI document automatically.

Defining one's own markup language (DTD) with XML is surprisingly simple. Using XML, enterprises have more options for the display and processing of incoming data. The Extensible Style Sheet Language (XSL) allows for the visual display of incoming data and formatting of those same data for further processing by corporate systems. In addition, more end-user application packages already support XML that enables the recipients to capture and process the incoming data directly. Even with legacy systems, industry groups can specify standard scripting language or Java code that reflects industry rules to provide for greater mapping and integration of data exchanged over the Web with XML.

XML can be integrated with the existing EDI systems by providing application specific forms, generating EDI message formats over the Internet or value added networks and allowing data received in EDI format to be interpreted according to predefined rules for display using a user-defined template. XML allows:

- Users to extend the EDI applications.
- Message creators to add application specific data to standardized message sets.
- Message creators and receivers to display the contents of the fields with explanatory material specific to the application and the preferences of the user.
- System developers to customize the help information associated with the data. XML allows field value checking.

Finally, XML makes applications implementation easier, allowing quicker reach into vertical markets, reduced message stores when processing transactions and enabling document-centric tools like search engines and push products to supplement database mechanisms.

Integration of EDI and XML

EDI information forms part of the logic structure of the XML document. Users can define their own element types to hold EDI information, so long as they label them with agreed attributes. A DTD can be created to formally defining the structure of EDI messages. EDIFACT/X12 messages can be placed in an XML shell element and the entire message or part of it can be in XML.

XML/EDI is the fusion of five technologies. The components are built on the top of existing standards for transmitting and processing XML-encoded data. The five technologies are XML, EDI, Templates, Agents and Repositories.

- XML provides the foundation. It brings all the rich capabilities and transport layers of the web.
- EDI gives the ability to express data in a simple format. XML/EDI provides backward capability to existing EDI transactions.

- Templates or Rules supplemented by the DTD's ensure that the transaction interoperability and processing is enabled. DTD's allow transaction interoperability. Templates allow rules to define the processing to be done on the transactions.

- Agents interpret the templates, interact with the transactions and allow the users to create new templates. Agents handle the processing required to analyze the data and provide a data interface to other systems.

- Repositories are shared directories that allow users and automated agents to lookup the meaning of the EDI element definitions. Traditional EDI systems support the manual user lookups only. The repositories can include the existing EDIFACT, X12 or BSI dictionaries. The Gartner Group expects EDIFACT and ANSI to operate XML repositories by the end of 2000.

Advantages of XML-EDI over Traditional EDI

1. Since the metadata is sent along with the data, data elements not used with a specific trading partner can still be sent or received without separate agreements or exception processing. This results in minimal trading partner-specific maps.

2. XML-based document formats can be shared by many different classes of applications, but rendered differently by each of the applications. This means that an EDI-XML agent, workflow agent, web browser, search engines and ERP applications can use the same document.

3. Unlike specific technical and software skills required for traditional EDI, technical skills and software tools like parsers, search engines can be leveraged across more than one class of application.

4. The usage of generic software tools and technical skills will lower the cost of implementation and allow easy implementation.

5. XML allows data elements to be created that contain both presentation and content metadata.

6. XML leverages on the web and TCP/IP infrastructures and tools. This means that the data can be accessed over the Internet infrastructure. It can be delivered in different mechanisms and displayed in various ways.

7. Interfacing with legacy systems combined with backward compatibility to existing EDI systems ensures that seamless integration is possible.

8. Enables flexible business models

9. Allows object-oriented documents since data and the rules reside together. This allows searches, archiving, reading and navigation simpler.

10. Allows interactive transactions rather than batch transactions.

Summary

XML based EDI provides the best means to perform Business to Business transactions in a cost effective and efficient manner. The Gartner Group predicts that by year-end 2002 XML-EDI will account for 30 percent of transactions with another 30 percent supported by XML-EDI to EDI gateways. Only 40% of transactions will be supported by traditional EDI. Combined with the inherent simplicity of using XML, it promises to be the next standard for automating business transactions.

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF COMPETITION IN THE	)	
PROVISION OF ELECTRIC SERVICES	)	DOCKET NO. RE-00000C-94-0165
THROUGHOUT THE STATE OF ARIZONA.	)	
	)	

JOINT APPLICATION OF THE PROCESS STANDARDIZATION WORKING GROUP FOR VARIATION/EXEMPTION OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1612

Pursuant to A.A.C. R14-2-1614(C), APS Energy Services, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Mohave Electric Cooperative, Navopache Electric Cooperative, New West Energy, Sulphur Springs Valley Cooperative, Teledata First Point, TRICO Electric Cooperative, and Tucson Electric Power Company, collectively referred to as "Parties" as members of the Process Standardization Working Group ("PSWG"), which includes APS Energy Services, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Computer Sciences Corporation, Energy Consulting & Design, EXCELERGY, GCSECA, Mohave Electric Cooperative, Navopache Electric Cooperative, New West Energy, Sulphur Springs Valley Cooperative, TeledataFirstPoint, TRICO Electric Cooperative, and Tucson Electric Power Company, the parties hereby jointly request the following variation/exemption from the provisions of A.A.C. R14-2-1612-K12. Specifically, A.A.C. R14-2-1612-K12 requires that, "North American Electric Reliability Council recognized holidays will be used in calculating "working days" for meter data timeliness requirements." The parties requests that A.A.C. R14-2-1612-K12 be modified such that holidays be recognized on the days that they are officially observed. For example, if a holiday officially occurs on a Saturday, the preceding Friday will be recognized as the date of the holiday. Likewise, if a holiday officially occurs on Sunday, the date of observance will be the following Monday.

GRANTING THE REQUESTED WAIVERS IS IN THE PUBLIC INTEREST

The Commission has formed and participated in a number of work groups to establish standards that foster and encourage competition. Recognizing holidays on the day they are officially observed will ensure consistency between all market participants in the calculation of working days for any processes with specific time requirements. The signatories in Attachment 1 respectively request this waiver. The signatories in Attachment 2 unanimously approve the recommended variation/exemption to the Electric Competition Rules pursuant to A.A.C. R14-2-1614(C).

RESPECTFULLY SUBMITTED this ____ day of ____ , 2000.

ATTACHMENT 1
JOINT WAIVER PARTICIPANTS

ARIZONA PUBLIC SERVICE

By: ____________________________

Title: ___________________________

APS ENERGY SERVICES COMPANY

By: ___________________________________

Title: __________________________________

ARIZONA ELECTRIC POWER COOPERATIVE

By: ____________________________

Title: ___________________________

CITIZENS UTILITIES COMPANY

By: ___________________________________

Title: __________________________________

MOHAVE ELECTRIC COOPERATIVE

By: ____________________________

Title: ___________________________

NEW WEST ENERGY

By: ___________________________________

Title: __________________________________

NAVOPACHE ELECTRIC COOPERATIVE

By: ____________________________

Title: ___________________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TELDATAFIRST POINT

By: ____________________________

Title: ___________________________

TRICO ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TUCSON ELECTRIC POWER COMPANY

By: ____________________________

Title: ___________________________

ATTACHMENT 2
PROCESS STANDARDIZATION WORKING GROUP

ARIZONA PUBLIC SERVICE

By: ____________________________

Title: ___________________________

APS ENERGY SERVICES COMPANY

By: __________________________________

Title: __________________________________

ARIZONA ELECTRIC POWER COOPERATIVE

By: ____________________________

Title: ___________________________

CITIZENS UTILITIES COMPANY

By: __________________________________

Title: __________________________________

COMPUTER SCIENCES CORP

By: ____________________________

Title: ___________________________

GCSECA

By: __________________________________

Title: __________________________________

ENERGY CONSULTING & DESIGN

By: ____________________________

Title: ___________________________

EXCELERGY

By: __________________________________

Title: __________________________________

MOHAVE ELECTRIC COOPERATIVE

By: ____________________________

Title: ___________________________

NEW WEST ENERGY

By: __________________________________

Title: __________________________________

NAVOPACHE ELECTRIC COOPERATIVE

By: ____________________________

Title: ___________________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TELDATAFIRST POINT

By: ____________________________

Title: ___________________________

TRICO ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TUCSON ELECTRIC POWER COMPANY

By: ____________________________

Title: ___________________________

Delivering More Than Power™

Post Office Box 52025
Phoenix, AZ 85072-2025

Ms. Deborah Scott
Arizona Corporation Commission
Utilities Division Director
1200 W. Washington Street
Phoenix, Arizona 85007

Re: ACC Process Standardization Working Group – Request for Variation/Exemption of Certain Requirements of A.A.C. R14-2-1612, Docket No. RE-00000C-94-0165

Dear Ms. Scott:

On May   , 2000 members of the Process Standardization Working Group (PSWG) that are under the jurisdiction of the ACC filed with your office a request for a variation/exemption from the provisions of A.A.C. R14-2-1612-K12 pertaining to the recognition of the North American Electric Reliability Council's holidays in calculating "working days" for meter data timeliness requirements. The PSWG is requesting that A.A.C. R14-2-1612-K12 be modified such that holidays be recognized on the days that they are observed. SRP, an ACC non-jurisdictional member of the PSWG, participated in the discussions leading up to the PSWG's recommendation and fully supports the requested rule variation/exemption. SRP is prepared to implement this change in its Direct Access processes and systems once the ACC approves this request for the utilities and parties under the ACC's jurisdiction in order to allow for statewide implementation.

If you have any questions, please direct them to Larry Nuszloch at (602) 236-3214.

Sincerely,

Michael W. Lowe
Manager, Customer Services - Power

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF COMPETITION IN THE	)	
PROVISION OF ELECTRIC SERVICES	)	DOCKET NO. RE-00000C-94-0165
THROUGHOUT THE STATE OF ARIZONA.	)	
	)	

JOINT APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY CITIZENS UTILITIES COMPANY AND TUCSON ELECTRIC POWER COMPANY, AS MEMBERS OF THE THE PROCESS STANDARDIZATION WORKING GROUP, FOR VARIATION/EXEMPTION OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1615

Pursuant to A.A.C. R14-2-1614(C), Arizo na Public Service Company (‘APS”), Citizens Utilities Company (Citizens), and Tucson Electric Power Company (“TEP”),collectively referred to as “Parties” as members of the Process Standardization Working Group (“PSWG”), which includes the Arizona Corporation Commission Staff, APS Energy Services, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Computer Sciences Corporation, Energy Consulting & Design, EXCELERGY, GCSECA, Mohave Electric Cooperative, Navopache Electric Cooperative, New West Energy, Sulphur Springs Valley Cooperative, TeledataFirstPoint, TRICO Electric Cooperative, and Tucson Electric Power Company. The Parties hereby jointly request the following variation/exemption from the provisions of A.A.C. R14-2-1615-B(1). Specifically, A.A.C. R14-2-1615-B(1) states that:

> “This Section does not preclude an Affected Utility or Utility Distribution Company from billing its own customers for distribution service, or from providing billing services to Electric Service Providers in conjunction with its own billing, or from providing Meter Services and Meter Reading Services for Load Profiled residential customers.”

APS, Citizens, and TEP request that the Commission grant a waiver of R14-2-1615-B(1) in order for all companies to apply the same standards to load-profiled commercial customers that are currently prescribed by the Rules for load-profiled <u>residential</u> customers. A waiver/exemption of the current Rule would allow APS, Citizens, and TEP to provide the same service, contemplated by the current Rule, to existing commercial customers, albeit either standard offer customers or those that choose an alternative provider(s) for various services.

GRANTING THE REQUESTED WAIVERS IS IN THE PUBLIC INTEREST

The Commission has formed and participated in a number of work groups to establish standards that foster and encourage competition. The current rule has the effect of preventing non-residential load profiled customers from having a choice. Market participants agree that it is too costly for alternative providers to read the meters for these customers and it is not cost effective to replace the existing meters. That is why these non-residential customers were permitted by the rules to be load profiled. The signatories in Attachment 1 respectively request this waiver. The signatories in Attachment 2 unanimously approve the recommended variation/exemption to the Electric Competition Rules pursuant to A.A.C. R14-2-1614(C).

RESPECTFULLY SUBMITTED this ____ day of ____ , 2000.

ATTACHMENT 1
JOINT WAIVER PARTICIPANTS

ARIZONA PUBLIC SERVICE

By: ___________________________

Title: __________________________

CITIZENS UTILITIES COMPANY

By: ___________________________

Title: ________________________________

TUCSON ELECTRIC POWER
COMPANY

By: ___________________________

Title: __________________________

ATTACHMENT 2
PROCESS STANDARDIZATION WORKING GROUP

ARIZONA PUBLIC SERVICE COMPANY	APS ENERGY SERVICES
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
ARIZONA ELECTRIC POWER COOPERATIVE	CITIZENS UTILITES COMPANY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
COMPUTER SCIENCES CORP	GCSECA
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
ENERGY CONSULTING & DESIGN	EXCELERGY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
MOHAVE ELECTRIC COOPERATIVE	NEW WEST ENERGY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________

NAVOPACHE ELECTRIC COOPERATIVE

By: ____________________________

Title: ___________________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TELDATAFIRST POINT

By: ____________________________

Title: ___________________________

TRICO ELECTRIC COOPERATIVE

By: ___________________________________

Title: __________________________________

TUCSON ELECTRIC POWER COMPANY

By: ____________________________

Title: ___________________________

Delivering More Than Power™

Post Office Box 52025
Phoenix, AZ 85072-2025

Ms. Deborah Scott
Arizona Corporation Commission
Utilities Division Director
1200 W. Washington Street
Phoenix, Arizona 85007

Re: ACC Process Standardization Working Group – APS, TEP and Citizens Utilities Request for Variation/Exemption of Certain Requirements of A.A.C. R14-2-1615,
Docket No. RE-00000C-94-0165

Dear Ms. Scott:

On May   , 2000 members of the Process Standardization Working Group (PSWG) that are under the jurisdiction of the ACC filed with your office a request for a variation/exemption for APS, TEP and Citizens Utilities pertaining to the provisions of A.A.C. R14-2-1615-B(1). Specifically, approval of the variation/exemption would allow APS, TEP and Citizens Utilities to apply the same standards to load-profiled commercial customers that are currently allowed by the rules for load-profiled residential customers, namely offering metering and meter reading services. SRP, an ACC non-jurisdictional member of the PSWG, participated in the discussions leading up to the PSWG's recommendation and fully supports the requested rule variation/exemption. Approval of this variation/exemption will have no impact on SRP as SRP is already allowed to provide metering and meter reading services to these affected customers under SRP's direct access rules and the Electric Power Competition Act.

If you have any questions, please direct them to Larry Nuszloch at (602) 236-3214.

Sincerely,

Michael W. Lowe
Manager, Customer Services - Power

April 7, 2000

P.O. Box 711
Tucson, AZ 85702

Deborah Scott
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2996

Dear Ms. Scott,

The PSWG members have been discussing the use of the Universal Meter Identifier (UMI). The UMI was presumed to be the national standard for identifying a single meter. However, it is not being used by any other state in the deregulation market. Furthermore most of the EDI documents are not implementing a UMI number. We have come to consensus that Arizona should not implement the use of the UMI.
The PSWG Membership respectively requests that you as Utilities Director direct your staff to remove this requirement to implement UMI in the operational procedures. This will serve the market and by doing it now will avoid cost of implementing. Attached is a signature list of the PSWG members who are requesting this change.

Sincerely yours,

Evelyn Dryer
Chairman PSWG

APPENDIX P4.1 - DRAFT

Delivering More Than Power™

Post Office Box 52025
Phoenix, AZ 85072-2025

Ms. Deborah Scott
Arizona Corporation Commission
Utilities Division Director
1200 W. Washington Street
Phoenix, Arizona 85007

Re: ACC Process Standardization Working Group – Request for Wording Change in Electric Competition Operational Procedures, Docket No. RE-00000C-94-0165

Dear Ms. Scott:

On May   , 2000 members of the Process Standardization Working Group (PSWG) that are under the jurisdiction of the ACC filed with your office a request for a wording change in the operational procedures for electric competition pertaining to the use of the Universal Meter Identifier (UMI). The PSWG is requesting that the use of UMI not be implemented in Arizona. While UMI was presumed to be a national standard for identifying a single meter, the PSWG has found that UMI is not being used in any other state in the deregulation market. In addition, most of the EDI (electronic) documents are not utilizing a UMI number. SRP, an ACC non-jurisdictional member of the PSWG, participated in the discussions leading up to the PSWG's recommendation and fully supports the requested wording change in the ACC's operating procedures for electric competition. The Commission's approval of this change will allow the utilities and other market participants to avoid the implementation costs of UMI without sacrificing any functionality or accessibility of the Direct Access process. SRP is prepared to implement this change in its Direct Access processes and systems once the ACC approves this request for the utilities and parties under the ACC's jurisdiction in order to allow for statewide implementation.

If you have any questions, please direct them to Larry Nuszloch at (602) 236-3214.

Sincerely,

Michael W. Lowe
Manager, Customer Services - Power

April 7, 2000

P.O. Box 711
Tucson, AZ 85702

Deborah Scott
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2996

Dear Ms. Scott,

The PSWG members have been discussing the issue of time stamped data. The participants feel it is important for acurate exchange of data to have a standardized time. We have come to a consensus that this should be tied to the Greenwich Mean Time (GMT).
At the present time the time standard in the operational procedures for MRSP's reads:
Time Standard: Meter reads are to be time-stamped to the nearest minute using local Arizona time and using a standard traceable to a national standard.
The PSWG members would like to see this language changed to:
Time Standard: All Arizona EDI (DASRs, 867, 810, 650) should utilize GMT standard time for the business transactions and local time for the enveloping.
The PSWG Membership respectively request that you as the Utilities Director direct your staff change the wording in the operational procedures. This will serve the market and by doing it now will avoid additional cost of implementing a national standard later. Attached is a signature list of the PSWG members who are requesting this change.

Sincerely yours,

Evelyn Dryer
Chairman PSWG

Delivering More Than Power™

Post Office Box 52025
Phoenix, AZ 85072-2025

Ms. Deborah Scott
Arizona Corporation Commission
Utilities Division Director
1200 W. Washington Street
Phoenix, Arizona 85007

Re: ACC Process Standardization Working Group – Request for Wording Change in Electric Competition Operational Procedures, Docket No. RE-00000C-94-0165

Dear Ms. Scott:

On May   , 2000 members of the Process Standardization Working Group (PSWG) that are under the jurisdiction of the ACC filed with your office a request for a wording change in the MRSP operational procedures for electric competition pertaining to the time standard. The PSWG is requesting that the time standard be changed to require the use of the Greenwich Mean Time (GMT) for all EDI business transactions and local time for enveloping. SRP, an ACC non-jurisdictional member of the PSWG, participated in the discussions leading up to the PSWG's recommendation and fully supports the requested wording change in the ACC's operating procedures for electric competition. SRP is prepared to implement this change in its Direct Access processes and systems once the ACC approves this request for the utilities and parties under the ACC's jurisdiction in order to allow for statewide implementation.

If you have any questions, please direct them to Larry Nuszloch at (602) 236-3214.

Sincerely,

Michael W. Lowe
Manager, Customer Services - Power

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	))))	DOCKET NO. RE-00000C-94-0165

JOINT APPLICATION OF THE PROCESS STANDARDIZATION WORKING GROUP FOR VARIATION/EXEMPTION OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1612

Pursuant to A.A.C. R14-2-1614(C), APS Energy Services, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Mohave Electric Cooperative, Navopache Electric Cooperative, New West Energy, Sulphur Springs Valley Cooperative, Teledata First Point, TRICO Electric Cooperative, and Tucson Electric Power Company, collectively referred to as “Parties” as members of the Process Standardization Working Group (“PSWG”), which includes APS Energy Services, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Computer Sciences Corporation, Energy Consulting & Design, EXCELERGY, GCSECA, Mohave Electric Cooperative, Navopache Electric Cooperative, New West Energy, Sulphur Springs Valley Cooperative, TeledataFirstPoint, TRICO Electric Cooperative, and Tucson Electric Power Company, hereby jointly request the following variation/exemption from the provisions of A.A.C. R14-2-210-(B)2 and A.A.C. R-14-2-1612(N). Specifically, A.A.C. R14-2-210- (B) 2 and A.A.C. R-14-2-1612 (N) require that certain elements of “rates and charges” be itemized on a customer’s bill. A.A.C. R14-2-210- (B) 2 essentially refers to A.A.C. R-14-2-1612 (N), which prescribes those items that, must be included on a customer’s bill. It is the consensus of the PSWG, that all entities regardless of status (i.e., Affected Utilities, Energy Service Providers, Meter Service Providers, etc.), be required to provide specific line items identifying all components of a customer’s bill for which that entity provides service. To the extent that various entities are not providing those services outlined in A.A.C. R14-2-1612 (N), the PSWG respectfully requests that the billing entities not be required to enumerate specific line items for services that they do not provide.

GRANTING THE REQUESTED WAIVERS IS IN THE PUBLIC INTEREST

The Commission has formed and participated in a number of work groups to establish standards that foster and encourage competition. The signatories in Attachment 1, collectively known as the Process Standardization Working Group ("PSWG"), unanimously approve the recommended variation/exemption to the Electric Competition Rules pursuant to A.A.C. R14-2-1614(C).

RESPECTFULLY SUBMITTED this __ day of ____ 2000.

ATTACHMENT 1
JOINT WAIVER PARTICIPANTS

ARIZONA PUBLIC SERVICE COMPANY

By: ____________________________

Title: ____________________________

APS ENERGY SERVICES

By: ____________________________

Title: ____________________________

ARIZONA ELECTRIC POWER COOPERATIVE

By: ____________________________

Title: ____________________________

CITIZENS UTILITIES COMPANY

By: ____________________________

Title: ____________________________

MOHAVE ELECTRIC COOPERATIVE

By: ____________________________

Title: ____________________________

NEW WEST ENERGY

By: ____________________________

Title: ____________________________

NAVOPACHE ELECTRIC COOPERATIVE

By: ____________________________

Title: ____________________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

By: ____________________________

Title: ____________________________

TELDATAFIRST POINT

By: ____________________________

Title: ____________________________

TRICO ELECTRIC COOPERATIVE

By: ____________________________

Title: ____________________________

TUCSON ELECTRIC POWER COMPANY

By: ____________________________

Title: ____________________________

ATTACHMENT 2
PROCESS STANDARDIZATION WORKING GROUP

ARIZONA PUBLIC SERVICE COMPANY	APS ENERGY SERVICES
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
ARIZONA ELECTRIC POWER COOPERATIVE	CITIZENS UTILITIES COMPANY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
COMPUTER SCIENCES CORP	GCSECA
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
ENERGY CONSULTING & DESIGN	EXCELERGY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
MOHAVE ELECTRIC COOPERATIVE	NEW WEST ENERGY
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________

NAVOPACHE ELECTRIC COOPERATIVE

By: ___________________________

Title: __________________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

By: _________________________________

Title: _________________________________

TELDATAFIRST POINT

By: ___________________________

Title: __________________________

TRICO ELECTRIC COOPERATIVE

By: _________________________________

Title: _________________________________

TUCSON ELECTRIC POWER COMPANY

By: ___________________________

Title: __________________________

Delivering More Than Power™

Post Office Box 52025
Phoenix, AZ 85072-2025

Ms. Deborah Scott
Arizona Corporation Commission
Utilities Division Director
1200 W. Washington Street
Phoenix, Arizona 85007

Re: ACC Process Standardization Working Group – Request for Variation/Exemption of Certain Requirements of A.A.C. R14-2-1612, Docket No. RE-00000C-94-0165

Dear Ms. Scott:

On May , 2000 members of the Process Standardization Working Group (PSWG) that are under the jurisdiction of the ACC filed with your office a request for a variation/exemption from the provisions of A.A.C. R-14-2-210-B2 and R-14-2-1612-N pertaining to the requirement that certain elements of "rates and charges" be itemized on a customer's bill. The PSWG is specifically requesting that the billing entities not be required to enumerate specific zero dollar line items for services. SRP, an ACC non-jurisdictional member of the PSWG, participated in the discussions leading up to the PSWG's recommendation and fully supports the requested rule variation/exemption. SRP is prepared to implement this change in its Direct Access processes and systems once the ACC approves the request for the utilities and parties under the ACC's jurisdiction to allow for statewide implementation.

If you have any questions, please direct them to Larry Nuszloch at (602) 236-3214.

Sincerely,

Michael W. Lowe
Manager, Customer Services - Power

Billing Subcommittee Appendix Documents

Business Processes Comparison for ESP Consolidated Billing

UDC & Cooperative Business Rules -- Page 68 -82
AZ Best Practice, CUBR, UBP & California – Page 83 - 93

#	Business Area/Rule	APS	SRP	TEP	TRICO	Other (Co-ops) [Graham County and Duncan tend to be different]	Citizens Utilities Company
1	Bill is generated by UDC	Yes	N/A	Yes	N/A	Yes	Yes
2	Need meter reads for metered accounts to bill	Yes	Yes	Yes	N/A	Yes	Yes
3	Third parties may read the meter (per the rules)	Yes	N/A	Yes	N/A	Yes	Yes
4	Each party is performing validation on meter and billing data	Yes	N/A	Yes	N/A	Yes	Yes
5	UDC is not required to pay ESP for ESP charges for UDC consolidated until the customer pays the UDC	Yes	N/A	Yes	N/A	Yes	Yes

6	ESP is liable to the UDC for UDC charges for ESP consolidated billing	Yes	N/A	Yes	N/A	Yes	Yes
7	Each UDC associates a customer to a billing cycle	Yes	Yes	Yes	N/A	Yes	Yes
8	UDCs and ESPs rely on electronic data	Yes	N/A	Yes	N/A	Yes	N/A
9	Bills are presented in US currency only	Yes	Yes	Yes	N/A	Yes	Yes
10	Rate Structure	3 Direct Access Rates – 2 commercial and 1 residential	Direct Access rate for every Standard Offer rate (exception: prepaid metering rate).	Direct Access rate for every Standard Offer rate.	N/A	Direct Access rate for every Standard Offer rate.	Direct Access Rate for every Standard Offer Rate
11	Validation Rules	Not addressed at this time	Not addressed at this time	Not addressed at this time	N/A	Not addressed at this time	N/A
12	Due date on bill	All bills rendered by the Company are due and payable no later than 15 calendar days from the billing date	21 calendar days from bill date (Bill date and Invoice date mean the same)	Payments for TEP products and services shall be delivered to TEP within 10 business days of the TEP invoice date. (Bill date and Invoice date mean the same)	N/A		All bills rendered by the company are due and payable 15 days from billing date
13	Number of billing cycles in a month	21	21	21	N/A	9 (Navopache)	9

14	Number of days in cycle	No less than 25 days and no more than 35 days	26 - 32	No less than 25 days and no more than 35 days	N/A		25-35
15	Time frame between read date & bill date	3-7 Calendar days	1-3 Calendar days	0-5 Working days	N/A		1-3 calander days
16	Bill data will be transported to the ESP via	Value Added Network (VAN)	Not applicable for ESP Consolidated Billing. Data transport is Internet EDI for all data transactions except 820.	Exolink (VAN)	N/A		N/A
17	Data security for billing information	APS relies on the VAN to provide data security. Data is sent over a secured socket to the VAN	S/MIME	TEP encrypts before transmitting to Exolink and Exolink handles the security to Trading Partner.	N/A		N/A
18	Delivery timeframe for bill ready data to ESP	810 will be sent the same day as the bill date	N/A	Flat file will be sent to Exolink same day as bill date, Exolink will send to Trading Partner the same day	N/A		N/A
19	Dispute resolution process for meter reads between UDC & ESP	If APS is the MRSP, the ESP may request a verify read. The cost of such rereads, which is $10, may be charged to the ESP, provided that the original reading was not in error.	If SRP is the MRSP, the ESP may request a verify read. The cost of such rereads, is $__ for Metro Area and &___ outside Metro Area, may be charged to the ESP, provided that the original reading was not in error.	The MRSP shall, at the request of its customer, the customer's ESP, TEP or the billing entity, reread that customer's meter within ten working days of the original read and post the read to read servers. Any meter reread costs may be charged to the entity requesting reread, provided the original reading was not in error.	N/A		N/A

20	Dispute resolution process for meter reads between UDC & customer	If APS is the MRSP, the customer may request a verify read. The cost of such rereads, which is $10, may be charged to the Customer, provided that the original reading was not in error.	If SRP is the MRSP, the ESP may request a verify read. The cost of such rereads, a charge $__ for Metro Area and &___ outside Metro Area, may be charged to the ESP, provided that the original reading was not in error.	The MRSP shall, at the request of its customer, the customer's ESP, TEP or the billing entity, reread that customer's meter within ten working days of the original read and post the read to read servers. Any meter reread costs may be charged to the entity requesting reread, provided the original reading was not in error.	N/A		N/A
21	Dispute resolution process for bill data between UDC & ESP	ESP notifies APS via e-mail or phone of any disputed bill data. APS will research disputed data and re-bill if needed.		The ESP shall be responsible for notifying the customer and adjusting the bill for ESP charges affected by the meter or billing error. TEP shall be responsible for any recalculation of any incorrect TEP charges. Following the receipt of any recalculated charges from TEP, the ESP will apply the charges or credits to the customer's next normal monthly bill, unless the parties otherwise agree that the ESP send an interim bill including the TEP charges to the customer. TEP will transmit corrected billings to the ESP for incorporation in the customer's bill using one of the following methods:	N/A		N/A

				a. By sending a cancellation notice, which cancels the bill in its entirety, and if appropriate, a re-bill will be included in same transmission. b. By transmitting an adjustment amount with a description of the adjustment.			
22	Dispute resolution process for bill data between UDC & customer	Customer notified APS via phone of any disputed bill data. APS will research disputed data and re-bill if needed.	Customer notified SRP via phone of any disputed bill data. APS will research disputed data and re-bill if needed.	The ESP shall be responsible for notifying the customer and adjusting the bill for ESP charges affected by the meter or billing error. TEP shall be responsible for any recalculation of any incorrect TEP charges. Following the receipt of any recalculated charges from TEP, the ESP will apply the charges or credits to the customer's next normal monthly bill, unless the parties otherwise agree that the ESP send an interim bill including the TEP charges to the customer. TEP will transmit corrected billings to the ESP for incorporation in the customer's bill using one	N/A		Customer notifies Citizens via phone or office visit of any disputed bill data. Citizens will research disputed data and rebill if needed.

				of the following methods: TEP will transmit corrected billings to the ESP for incorporation in the customer's bill using one of the following methods: a. By sending a cancellation notice, which cancels the bill in its entirety, and if appropriate, a re-bill will be included in same transmission. b. By transmitting an adjustment amount with a description of the adjustment.			
23	Bill inserts & how delivered to ESP	All APS customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, APS shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed customers. If APS is providing consolidated billing services, APS shall continue to mail these notices in the billing	N/A	All TEP customers, including Direct Access customers, shall be provided with all mandated legal, safety and other notices in accordance with ACC regulations. TEP shall make available one hard copy of all mandated legal, safety and other notices per customer to the ESP for distribution to its customers, or at the ESP's request, in electronic format for production and communication to its electronically billed customers. TEP and the ESP may agree to use e-mail to provide language that is to	N/A		N/A

		envelope and may use the billing envelope as it does in current practices for providing such information.		appear in printed format on the ESP consolidated bill. Messages to a specific customer may be inserted in description lines included with calculated TEP charges.			
24	Data file format	EDI 810 version 4010	N/A	Flat files sent via Exolink (will transmit the file as it was submitted from Tucson or for a fee to the ESP, transmit it as the ESP requests. After AZ 810 is standardized, Exolink will transmit using the AZ 810)	N/A		N/A
25	How & when data is estimated & who does the estimation	The MRSP designated for the customer account is the responsible party for performing and communicating the estimated read. Estimated reads can occur if the MRSP is unable to get reads due to access issues, extreme weather conditions, equipment failure or if a customer who reads his own meter fails to deliver his meter reading data etc. -- When APS is the MRSP, the		All estimated interval or monthly meter reads shall be sent to TEP using the EDI format. Meters will be estimated on date set forth in the TEP Meter Reading Schedule. Reads will be posted by the MRSP to the TEP FTP server by 3:00 p.m. the day following the meter read for the meters that the MRSP is responsible for reading. The meter reads from TEP will be available on the TEP	N/A		N/A

		meter read estimates will be based on either the customer usage during the same month of the previous year or based on the amount of usage during the preceeding month (article 2-210)		FTP server by 3:00 p.m. the day following the meter read for the meters that TEP is responsible for reading. All estimated data will be clearly marked with an explanation of the reason for the estimation.			
26	Disconnect & reconnect for nonpayment	**DOESN'T APPLY TO ESP CONSOLIDATED** APS will notify the customer and the customer's ESP of intent to disconnect. APS will also notify the ESP once the customer is disconnected. A service charge will be imposed on the customer if a filed call is performed to leave door hanger or collect. APS will reconnect electric service for a service fee when the criteria for reconnection has been met.	**DOESN'T APPLY TO ESP CONSOLIDATED** SRP will notify the customer and the customer's ESP of intent to disconnect. SRP will also notify the ESP once the customer is disconnected. SRP will reconnect electric service for a service fee when the criteria for reconnection has been met.	**DOESN'T APPLY TO ESP CONSOLIDATED** In the event of Direct Access customer non-payment of charges for TEP provided services, TEP will be responsible for all physical disconnect activity regardless of the MSP or ESP servicing that customer. Disconnection can occur at any time after the payment due date for non-payment of any TEP-provided service. TEP will send a copy of the Direct Access customer's Disconnect Notice for non-payment to the ESP. This notice shall include customer name, address, notice date, account number, delinquent amount, total amount due, due date, the UNI number and ESP account number.	N/A		Doesn't apply to ESP consolidated billing. Citizens will notify the customer and the customers ESP of intend to disconnect. Citizens will also notify the ESP once the customer is disconnected. Citizens will reconnect electric service for a service fee when the criteria for reconnection has been met.

				TEP will notify the ESP at the end of each day which Direct Access customers remain disconnected. This notification will include the UNI number and ESP account number. With the exception of those customers who are reconnected the same day they were disconnected, TEP will notify the ESP when customers disconnected for non-payment are reconnected. This notification will include the UNI number and ESP			
27	Final bills for Bundled Charges	APS will not hold the ESP responsible for any customer Full Service final bills. The customer can be disconnected under his DA account for non-payment of APS final		TEP will not hold the ESP responsible for any customer Full Service final bills. The customer can be disconnected under his DA account for non-payment of TEP final	N/A		Citizens will not hold ESP responsible for any customer Full Service final bills. The customer can be disconnected under his DA account for non-payment of Citizens final bill.

28	Final bills for DA Charges			In the case of a physical disconnect final bill, TEP will provide the ESP with the TEP final bill charges by 3:00 p.m. on the fifth business day following the actual disconnect date. If TEP billing charges have not been received by such date, the ESP may render the bill without such TEP charges; however, the ESP shall include a message on the bill stating that said charges are forthcoming. TEP will then render a separate bill for the TEP charges, unless a mutual agreement is made between TEP and the ESP to have a final bill produced and sent to the customer for the TEP final charges. TEP charges shall be calculated based on the existing TEP billing cycles regardless of the party providing the meter reading. TEP charges shall be conveyed to the ESP using ExoTran™.	N/A		N/A

29	Back bills for customer billing	Persuant to Schedule 1, APS can backbill up to 6 months	UDC Consolidated - Back bill up to 6 months	Persuant to Article 24, TEP can backbill up to 6 months on a commerical customer and 3 months on a residential customer, or as far back as occurrence on tampering.	N/A		For the period of 3 months immediately preceding the removal of such meter from service for test or from the time it was in services since the last test, but not exceeding 3 months since the meter shall have been shown to be in error by the test. B. From the date the error occurred, if the date of the cause can be definitely fixed.
30	Theft or tampering	APS shall notify ESP immediately and ESP shall notify APS immediately of any suspected unauthorized energy use. ESP shall ensure that a heavy duty lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read or shall utilize a light duty lock ring to secure meters equipped with meter tamper reporting technology equipped with tamper reporting	SRP shall notify ESP immediately and ESP shall notify SRP immediately of any suspected unauthorized energy use. ESP shall ensure that a heavy duty lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read or shall utilize a light duty lock ring to secure meters equipped with meter tamper reporting technology equipped	In accordance with ACC rules, TEP has the right to disconnect electric service to the customer for a variety of reasons, including, but not limited to, the non-payment of TEP final bills or any past due charges by the customer, or evidence of safety violations, energy theft, or fraud, by the customer. TEP will perform the disconnect for non-payment regardless of the ESP. The following provides for service disconnects	N/A		N/A

		capabilities. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, APS, in its sole discretion, may take any or all of the actions permitted under APS' applicable tariffs and schedules and shall notify ESP of any such action taken. APS will coordinate with the ESP, the estimated amount of usage that will be back billed to the customer.	with tamper reporting capabilities. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, SRP in its sole discretion, may take any or all of the actions permitted under SRP applicable tariffs and schedules and shall notify ESP of any such action taken. SRP will coordinate with the ESP, the estimated amount of usage that will be back billed to the customer.	and reconnects.TEP shall notify the customer and the customer's ESP of TEP's intent to disconnect electric service for the non-payment of TEP charges prior to disconnecting electric service to the customer. TEP shall further notify the ESP at the time the customer has been disconnected. To the extent authorized by the ACC, a service charge may be imposed on the customer if a field call is performed to disconnect electric service.			
31	Policy for ESPs to change customer's UDC billing cycle	Currently, this is not an option	N/A	This is not an option at this time.	N/A		This is not an option
32	When are new account numbers assigned	If the customer is an existing APS customer switching to DA, a new UDC Customer Account Number will be assigned during the processing stages of each incoming RQ DASR. If the customer is a new customer within APS' territory, a new UDC Customer Account Number will be assigned during the initial application with our call center. In addition, the	Assigned during re-districtricting and if certain order work is performed,	UDC Customer Account Numbers are tied to the customer and do not change.	N/A		UDC Customer account numbers are assigned and are tied to their location. Their CID (customer ID) number doesn't change.

		account number could change if certain order or billing work is done.					
33	When is a new read cycle assigned	During re-districting.		During re-districting (TEP has not redistricted in 5 years.)	N/A		N/A
34	How are customer deposits handled for each billing options	**Dual Billed** - only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded. **ESP Consolidated** - 100% of the customer deposit is applied to the Standard Offer final bill and any remaining deposit will be refunded to the customer. **UDC Consolidated** - only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded.	**Dual Billed** - only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded. **ESP Consolidated** - 100% of the customer deposit is applied to the Standard Offer final bill and any remaining deposit will be refunded to the customer. **UDC Consolidated -** only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded.	**Dual Billed** - only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded. **ESP Consolidated** - 100% of the customer deposit is applied to the Standard Offer final bill and any remaining deposit will be refunded to the customer. **UDC Consolidated** - only retain portion of the deposit to secure the UDC charges only, the remaining deposit will be refunded.	N/A		Dual Billed - only retain portion of deposit to secure the UDC charges - only, the remaining deposit will be refunded. ESP Consolidated - 100% of customer deposit is applied to the standard offer Final Bill and any other remianing deposit will be refunded to the customer. UDC Consolidated N/A
35	How are rebate/rebills handled	Reverse the bill that was produced in error and rebill with correct information in the same transaction.			N/A		N/A
36	Will billing service End and Beginning periods	Yes	N/A	Yes	N/A		N/A

	be passed in the 810						
37	Will customer payment date be passed on the 810 for ESP Consolidated	No	N/A	No	N/A		N/A
38	Will levelized billing be offered to Direct Access customers for UDC charges	No for ESP Consolidated. Yes for Dual and UDC Consolidated billing and	Yes for UDC and Dual Billing	No	N/A		N/A
39	Will Summary billing be offered to Direct Access customers?	NO for ESP Consolidated billing. Yes for Dual and UDC Consolidated billing		No	N/A		N/A
40	What is the billing compliance testing procedure?	Not addressed at this time	Not addressed at this time	Not addressed at this time	N/A	Not addressed at this time	N/A
41	Notification buy ESP to UDC of billing option change				N/A		
42	Elements on ESP consolidated bill				N/A		
43	Access for uncollectible accounts to SHARE or charitable service funds.				N/A		

#	AZ BEST PRACTICE	CUBR	EEI/UBP	Calif.
1	Bill is generated by UDC	Yes	Yes	In "Partial Consolidated" UDC calculates including taxes & surcharges and delivers to ESP using UDC's normal billing cycle. If ESP reads meater, it must provide UDC data in time to bill. Another option is "Full consolidated" where ESP calculates UDC charges.
2	Need meter reads for metered accounts to bill			Yes
3	Third parties may read the meter (per the rules)			Yes
4	Each party is performing validation on meter and billing data			
5	UDC is not required to pay ESP for ESP charges for UDC consolidated until the customer pays the UDC			
6	ESP is liable to the UDC for UDC charges for ESP consolidated billing	Yes, per the UDC's tariff schedule,for all undisputed UDC charges. The receipt of UDC charges by the ESP starts the cycle. UDC is notified by ESP, of disputed charges, electronically.		Yes, all undisputed charges.
7	Each UDC associates a customer to a billing cycle			
8	UDCs and ESPs rely on electronic data	Yes	Both supplier and utility must demonstrate the technical capability to exchange information electronically using the standardized electronic transactions.	electronic transmittal or other means…

9	Bills are presented in US currency only			
10				
11		For charges sent to billing party, billing party has 48 hours to reject non-billing party file. Billing party must send electronic rejection with codes. Also, billing party must send electronic notification to non-billing party if bill not issued(no time		
12			(6) The due dates, and other payment terms and conditions must be identical for Supplier and Utility charges when a consolidated bill is rendered.	
13				
14				
15			c. The Non-Billing Party Charges must be received by the Billing Party within forty-eight (48) hours commencing on the first business day following receipt of valid usage data. Usage data shall be made available to all parties in sufficient time to ensure the utility bill is not delayed from the utility's normal billing cycle.	

16				electronic transmittal or other means…
17				
18		Electronic file within 72 hours commencing on the first business day following receipt of valid usage data.	Must meet the operational time frames which have been defined to support the billing options available.	
19		If unresolved within 30 days, may go to mediation or binding arbitration, by mutual agreement.		
20				UDC transmits revised charges to the ESP and the customer will be responsible for obtaining refunds of overcharges from the ESP. For undercharges, the ESP may either pay the utility the adjusted charges and collect them from the customer or file a DASR to switch to separate billing.

21			Acceptance or rejection(by billing party), accompanied by appropriate error code(s), shall be communicated via the appropriate standardized electronic transaction within forty-eight (48) hours commencing upon receipt of the charges. If the transaction is deemed accepted, then within forty-eight (48) hours the Billing Party must bill or notify the Non-Billing Party via the appropriate standardized electronic transaction when a bill is not issued. (2) If the Non-Billing Party's Charges are received within the appropriate time frame and the transaction is rejected, the Non-Billing Party may, if time permits, resubmit a corrected file containing billing charges for inclusion in the current billing statement, subject to the same conditions as listed above. (3) If the Non-Billing Party Charges are sent to the Billing Party outside the appropriate time frame, then the Billing Party should reject the transaction and notify	

			the Non-Billing Party within forty-eight (48) hours via standardized electronic transac	
22				Adjust its bill to the ESP. Within 15 days of the UDC sending the adjusted bill, the ESP may either assume responsibility for the adjusted charges, or file a DASR to switch to separate billing.

23			Billing party responsible for delivering information to customers which is mandated by regulations.	
24			Both supplier and utility must demonstrate the technical capability to exchange information electronically using the standardized electronic transactions.	
25				

26			Utility may disconnect for non-payment of supplier charges if permitted by laws and regulations. Suppliers shall indemnify the utility against any claims by the customer.	
27		Outstanding prior balances are not transferred in any switch, UDC to ESP, ESP to ESP, ESP to UDC.	Outstanding prior balances are not transferred when a customer switches from the Utility to a Supplier, switches from one Supplier to another, or switches from a Supplier to default generation service. The Utility or Supplier may deny the Consolidated Billing option to a customer if the customer's account is at least thirty (30) days overdue.	

28				
29				
30				

31		ESP can request adjustment to meter read/billing cycle. But ESP must select another UDC defined read schedule(unless customer has remote read).	Any party which uses metering data in its business processes can request a change in meter read date. Whether or not to change a meter read date should be determined by the metering entity. The metering entity should be enabled to make changes of meter read date, subject to objective guidelines which are mutually acceptable to affected parties and with proper advance notice.	
32				
33				
34				
35				
36				
37				

38		Billing party may offer, but if it does, it must provide for both ESP and UDC.	Other billing features, such as budget, or equal monthly, billing may be offered by the Billing Party, provided the Billing Party and the Non-Billing Party agree. Each party is responsible for deciding whether to offer budget billing for its charges only. Neither party is required to offer budget billing for the other party's charges.	
39				
40				
41		60 days	60 days	
42		Agreement of ESP and customer for Commercial and Industrial. Comply with applicable consumer laws for Residential	Supplier discretion, except for: separation of supplier and utility charges, large commercial/industrial customer and supplier may negotiate elements, for residential and small business customers the supplier must comply with applicable consumer laws and regs. Non electric services must be billed in separate section. Bill for generation services must separate consumption, pricing structure, total generation charge, total transmission charge.	

43		ESPs can access if they can't disconnect, for non-payment, due to regulations. This is for dual or consolidated billing.		

PSWG Billing Subcommittee Participation

Companies who participated were:

APS Energy Services
Arizona Corporation Commission
Arizona Electric Power Cooperative
Arizona Public Service
City of Mesa
Citizens Utilities
Excelergy
GCSECA
K.R. Saline & Associates
Mohave Electric Cooperative
Navopache Electric Cooperative
New West Energy
Salt River Project
Trico Electric Cooperative
Tucson Electric Power

Metering Systems and Meter Reading Subcommittee Appendix Documents

PSWG Metering Systems and Meter Reading Subcommittee Participation

Subcommittee Meetings were held on:

January 20, 2000
January 27, 2000
February 3, 2000
February 17, 2000
March 2, 2000
March 16, 2000
March 30, 2000
April 13, 2000

Companies who participated were:

APS Energy Service
Arizona Corporation Commission
Arizona Electric Power Cooperative
Arizona Public Service
Citizens Utilities
City of Mesa
Computer Sciences Services
Energy Consulting
Excelergy
GCSECA
K.R. Saline & Associates
Martinez & Curtis
Mohave Electric Cooperative
Navopache Electric Cooperative
New West Energy
Salt River Project
Schlumberger
Southwest Energy Solutions
Teldata FirstPoint
Trico Electric Cooperative
Tucson Electric Power

ESP Proposal Meter Exchange and Scheduling

Scope: The purpose of this proposal is to create a dialogue between the ESP and UDC on how best to structure the timing of Meter Exchanges and Meter Scheduling. Meter Exchange is the process of removing the current meter at the existing site to a "new" meter. Scheduling is the process used by ESPs to coordinate and communicate the date the meter exchange will take place.

Objectives of Standardizing the Meter Exchange and Scheduling

- Minimize the delay of implementation of customer choice
- Help develop a viable market which fosters a competitive market for Customer Choice
- Minimizes the burden to the customer, Customer and the UDC of partial billing periods
- Help foster new entrants to offer competitive metering

Background: Currently the protocols are as follows

The Period Of Time That An MSP Can Not Exchange The Meter (Blackout Window)

APS	SRP	TEP
An MSP can not exchange the meter 6 days prior to the first APS read date, through the read window. (3-5 working days)	No blackout window.	An MSP cannot exchange a meter 5 calendar days prior to a read date. (single day)

MSP/ESP Sends Scheduling Information to UDC

APS	SRP	TEP
MSP sends page 1 of MAC form back to APS with estimated scheduling information and pending ownership information and signed equipment purchase orders. Additional phone coordination is required for site meets. **Time Requirements:** Form must be returned at least 5 working days prior to the exchange.	MSP returns MI form (bottom half of form) to SPC with estimated scheduling information and pending ownership info. Additional phone coordination is required for the site meets. **Time Requirements:** Form must be returned at least 3 working days prior to the exchange.	MSP sends the MI form back with ownership changes and metering requirements indicated. Additional phone coordination is required for site meets. **Time Requirements:** The form must be returned 5 workdays prior exchange or install date.

Proposal for Ideal Meter Exchange and Scheduling

- The MSP may install the meter any business day <u>one day after the read date up to five days before the next read date</u>

- The MSP will notify the UDC of the anticipated installation date no later than 5 business days prior to the anticipated installation
- The UDC will read the meter from the date of installation to the next read date.
- The UDC and ESP should develop processes to ensure that the UDC will have full privileges for the purpose of reading the meter for billing purposes. We need much discussion about passwords, vendor software, standard meter reading protocol and meter displays. This is one of the reasons I brought up meter displays at the last Metering Subcommittee meeting. The industry is moving towards a standard reading protocol to address this UDC data needs, however, we are not there yet, and to my knowledge, little time is being spent to develop this protocol. There are a couple of software vendors that have a standard reading protocol. Multivend, a product developed by Itron/Utility Translation Systems, is the most predominant in the existing industry. I'm sure we will have some time to talk about this at our Metering meeting on March 2^{nd}.
- The ESP will be responsible for the power effective 12:01 a.m. on the read date or the first full interval (15 min) on the read date
- The ESP and UDC should ensure that processes are put in place to change the Meter Passwords and gain full control of the meter. Again, I have the same issues as mentioned in bullet #4 above.

Scenario:
- Customer requires an interval meter
- DASR has been accepted, assumes all is clear to install, No issues
- Customers Read Date is on April 14^{th} (Weekday) to May 15^{th}
- BD= Business Day

UDC Reads the Meter through Midnight day of the Read ESP responsible at 12:01		
No Exchanges	Exchange Period	No Exchanges

April 1

April 7
5 BD Prior to Read Date

April 14
Read Date (Friday)

April 15
First Business Day after the Read Date (Monday)

May 8
5 BD Prior to Read Date

May 15
Read Date Monday

Scheduling Proposal
- Return All information to the UDC 5 working days prior to the installation date
- Changes or add can be made 5 working days prior to the installation date
- Cancellations no change in current protocols

ALTERNATIVE ESP PROPOSAL
RE: METER EXCHANGE BLACKOUT PERIOD

Metering Group

March 16, 2000

This proposal has been prepared for consideration by the Metering Group as an *alternative* to the original ESP proposal currently under consideration to address the meter exchange blackout period issue.

Current Situation:

ÿ UDCs have varying periods of time that a meter cannot be exchanged prior to the read date/window for that account
  - APS = 6 working days prior to first date in read window through the end of the read window (3-5 working days)
  - TEP = 5 calendar days prior to the read date
  - SRP has no blackout period around the read date
  - Navopache = 5 calendar days prior to read date
  - Trico = 3 working days prior to the read date and 2 working days after the read date

ÿ In addition to the blackout period, UDCs require 5 days notice from an MSP prior to the meter exchange (MAC/MI form)

Issues:

ÿ UDCs need some notification of meter exchanges to be able to know whether they need to read the meter for that account or not

ÿ The blackout requirements create difficulty for MSPs to efficiently schedule meter exchanges, especially for customers with multiple accounts on various read cycles

Objective:

ÿ Propose a solution that balances the UDC need for notification with the MSP need to schedule meter exchanges in a more efficient fashion

Proposal:

ÿ Eliminate the blackout period around the meter read date for all UDCs and allow MSPs to exchange meters on any day, regardless of the read date

ÿ Maintain the 5 day notification period from the MSP to the UDC prior to a meter exchange to allow the UDC time to modify their read schedule

ÿ Establish the actual cutover time as the first full interval after the new meter is installed by the MSP

ÿ MSP would be responsible for taking final read from existing meter and providing that information to the UDC

ÿ Require the MSP to clock the time between the existing meter removal and new meter installation and provide this information to the UDC for estimation of usage

This proposed process is consistent with the way meter exchanges work in California.

METER EXCHANGE AND SWITCH DATES
HYBRID ESP PROPOSAL – March 22, 2000 Draft

PROPOSAL OVERVIEW:

Original Proposal:

- Customer switches on read date, rather than exchange date, eliminating partial bills to customer
- Maintains 5 day blackout period around read date plus 5 day notification of meter exchange

Alternative Proposal:

- Customer switches on exchange date, rather than read date, maintaining the need for partial bills to customer
- Eliminates blackout period around read date, but maintains 5 day notification of meter exchange

Hybrid Proposal:

- Provides option for either switching on exchange date or read date
- Eliminates blackout period, but maintains notification period
- Puts time requirements on when exchange must occur relative to read date if choosing option to switch customer on read date

---

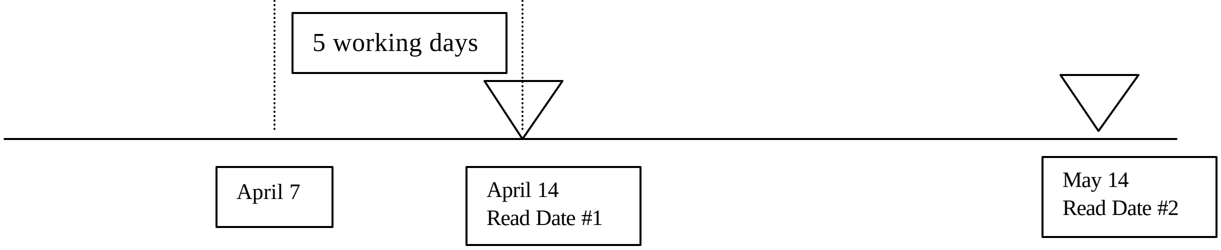
HYBRID PROPOSAL DETAILS:

- No blackout period – meters can be installed on any day of the month, including the read date for that account
- ESP has option of when customer switches between
  1. Meter exchange date
  2. Next read date
- Selected option would be indicated on MI form when sent to UDC, at least 5 working days prior to meter exchange
- Switch on meter exchange date would be allowed in ALL circumstances
- Switch on read date would NOT be allowed in the following circumstances:
  - a) Account is currently billed on UDC time-of-use rate or any other rate that the required billing determinants could not be provided from a DA interval meter
  - b) Exchange date is less than 5 working days prior to next read date, then exchange could still occur as requested, but switch date would not be until the following read date approximately 1 month later

  but switch on read date would be allowed in all other circumstances
- If switch on read date is chosen, then MRSP is responsible for providing final read from DA meter to UDC for preparing their final bill to the customer
- If switch on read date is chosen, then switch time is first full interval starting at 0:00 on the read date
- If switch on exchange date is chosen, then switch time is first full interval after the new meter is installed and the UDC estimates the usage from the removal of the old meter to the first full interval after the installation of the new meter

SCENARIO: (1 account – non-TOU)

METER EXCHANGES ALLOWED ANY DAY DURING MONTH (5 days notification required)		
Switch on Exchange Date OR Read Date #1	Switch on Exchange Date OR Read Date #2	Switch on Exchange Date OR Read Date #2



ADVANTAGES OF HYBRID PROPOSAL:

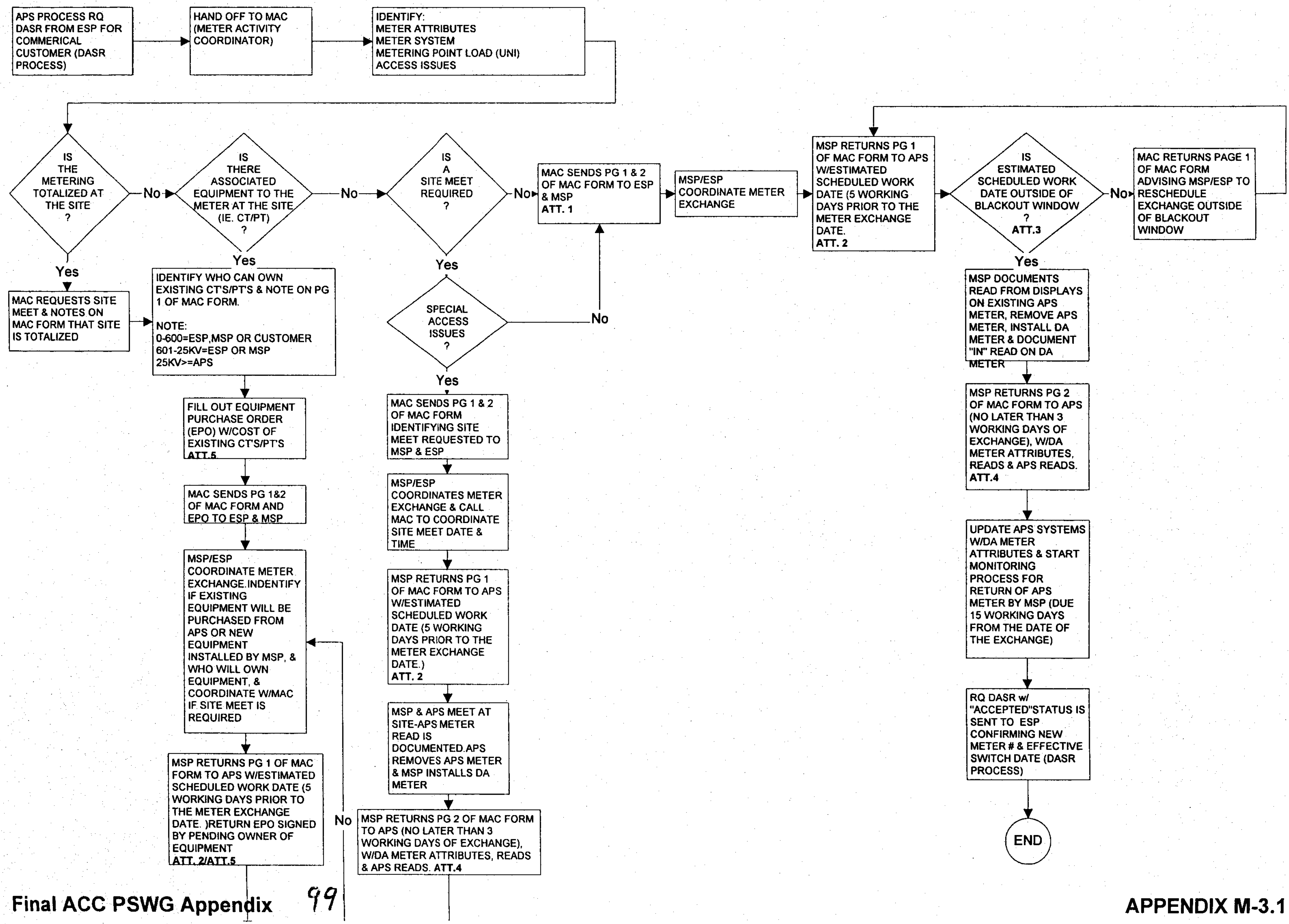
✓ CUSTOMER
- Avoids partial bills if switch on read date is chosen
- Preserves option to switch before read date to speed process

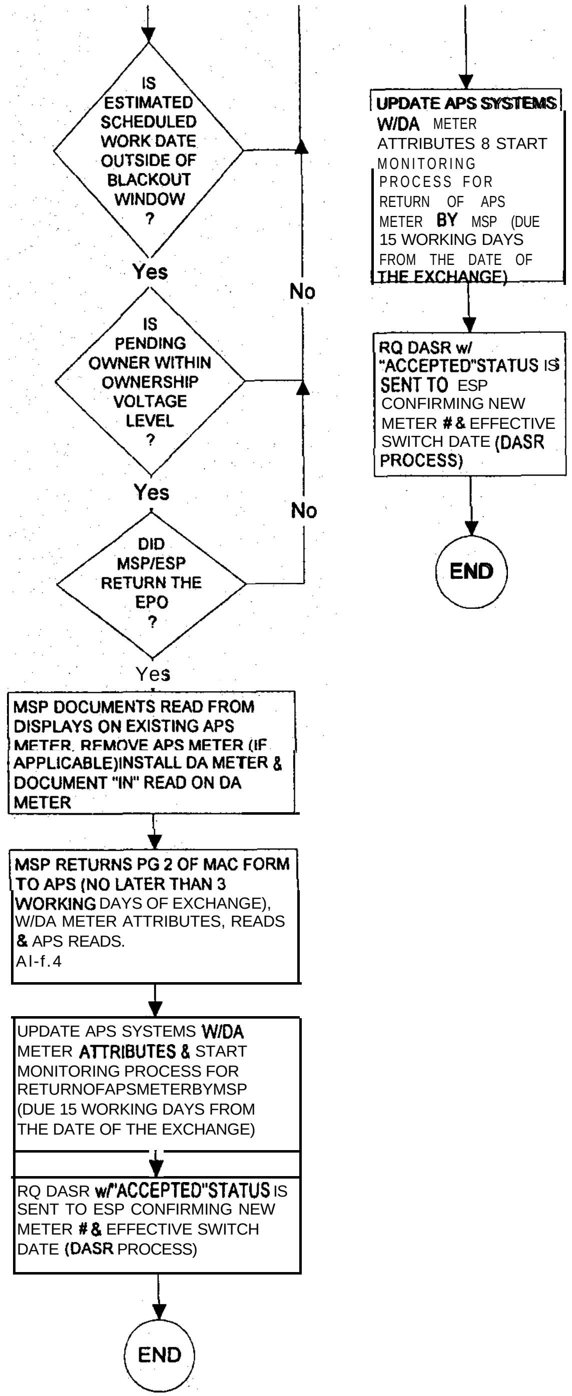
✓ UDC
- Consistent with SRP process of no blackout period and current APS practice of waiving blackout period
- Maintains 5 day blackout period prior to read date if choosing to switch on read date
- Maintains 5 day notification for meter exchanges
- Does not require UDCs to read DA meters

✓ ESP
- Can choose to switch on read date to avoid partial bills if desired by customer
- Can choose to switch on exchange date to speed transition if desired by customer
- Can schedule power with more certainty if switch on read date is chosen

✓ MSP/MRSP
- Allows more efficient scheduling of meter installations for multiple accounts in a geographic area by removing blackout period restrictions
- Allows for some testing of meter reading process prior to first EOC if switch on read date is chosen

APS FULL SERVICE CUSTOMER TO DIRECT ACCESS METER EXCHANGE





Appendix M-3.1

ATTACHMENTS

Attachment 1 = MAC form pg 1 & 2 with APS information

Attachment 2 = MAC form pg 1 with MSP information

Attachment 3 = APS Yearly Meter Reading and Bill Date Schedule

Attachment 4 = MAC form pg 2 with MSP information

Attachment 5 = Equipment Purchase Order (EPO)

APPENDIX M-3.1

METER ACTIVITY COORDINATION FORM FOR APS SERVICE AREA

Page 1

INSTRUCTIONS:

- **ESP/MSP:** Complete the applicable **shaded** fields. Return to APS a minimum of 5 working days prior to scheduled work date.

General Information

Customer Name		Date Sent	
Business Name		Existing Meter #	
Service Address		Universal Node ID (UNI)	
Bldg/Unit		Universal Meter ID (UMI)	
Service City/Town		ESP Company Name	

MSP Information

Company Name	
Local Field Contact	
Local Field Contact Phone #/Pager #	

Scheduling

DASR Request:

Install Meter ☐ Exchange Meter ☐ Remove Meter ☐ APS will/or has removed non-APS owned Meter ☐

APS scheduled work date:_________________

☐ **CANCEL MAC FORM - REASON:**

APS Billing Cycle		MSP Scheduled Work Date:______________________ (outside of APS scheduled read date window)
ESP Requested Cutover Date		
Site Meet*Requested By APS ☐ MSP ☐ *Call APS MAC to coordinate site meet before returning this form.		☐Exact Cutover Date Requested* ☐APS ☐MSP

Agreed Upon Site Meet Date: Time:

Ownership

Current Owner of:	Pending Owner of:
Meter: APS ☐ ESP ☐ MSP ☐ Customer ☐ N/A ☐	Meter: APS ☐ ESP ☐ MSP ☐ Customer ☐
CT/PT: APS ☐ ESP ☐ MSP ☐ Customer ☐ N/A ☐	CT/PT: APS ☐ ESP ☐ MSP ☐ Customer ☐ N/A ☐

☐ Totalized/Combined Account (please contact MAC)

Misc Existing Equipment

Purchase existing CT/PT's? ☐ Yes** ☐ No ☐ N/A	Purchased by: APS ☐ ESP ☐ MSP ☐ Customer ☐

Purchase existing totalized/combined equipment? ☐ Yes** ☐ No ☐ N/A	Purchased by: APS ☐ ESP ☐ MSP ☐ Customer ☐

**If yes, return attached Equipment Purchase Order Form with this page. ☐Equipment Purchase Order attached

Remarks:____

METER ACTIVITY COORDINATION FORM FOR APS SERVICE AREA **Page 2**

INSTRUCTIONS: Complete the applicable fields on page 2 and **return to APS within 3 working days of completion of work order**.

- **ESP/MSP:** For ESP to ESP meter exchanges complete all applicable fields on page 2, regardless of shading. Return to APS within 3 working days of meter exchange.

Date Sent:

Customer Name		Universal Node ID (UNI)	
Service Address		Business Name	
Service City/Town		Bldg/Unit	
MSP Company Name		Date/Time Completed	
ESP Company Name		☐APS Medical Monitoring	☐ Voltage Monitoring Equipment

Order Type

Install Meter ☐ Exchange Meter* ☐ Remove Meter ☐ Shop Test** ☐ Field Test** ☐

Investigate Meter: Dead Meter ☐ Clock ☐ Display Blank ☐ Error Code ☐ **Reads set to ZERO** ☐

Other ☐ Explain:

Meter Information	Existing	New
Owner		
Meter Number		
Universal Meter ID		
Serial Number		
Meter Model /Type		
Register Model/ Type		
Form Number (s)		
IDR Recorder	YES ☐ NO ☐	YES ☐ NO ☐
Test Amps		
Meter Voltage		
Disk Cnstnt (Kh)		
Dial Cnstnt (multiplier)		
Customer Pulse (Ke)		
Most Recent Calibration Test		

Reads	Existing	New
Hard Dial KWH		
Hard Dial KW		
Display 01		
Display 02		
Display 03		
Display 04		
Display 05		
Display 06		
Display 07		

New Meter display Locations:

	Display #	# of Dials	Decimal Values
kWh			
Kw			

**Test Results	As Found	As Left
Unity F.L. %		
0.5 PF %		
Unity L.L. %		
Kw Accuracy		
Program OK?	☐ YES	☐ NO
Avg. Phs Angle %		

***If APS meter/equipment, returning meter to APS via:**

☐ Ship to MAC

Deliver to:
☐ MAC Office
☐ Casa Grande Office
☐ Cottonwood Office
☐ Flagstaff Office
☐ Yuma Office

Physical Condition of Meter:
☐ Good ☐ Damaged
If damaged, still return to APS

Existing Owner:	**CT 1**	**CT 2**	**CT 3**	**PT 1**	**PT 2**	**PT 3**
Ratio::						
Type						
ID #:						
Serial #						
Physical Condition of return	☐ Good ☐ Damaged	☐ Good ☐ Damaged	☐ Good ☐ Damaged	☐ Good ☐ Damaged	☐ Good ☐ Damaged	☐ Good ☐ Damaged
New Owner:	**CT 1**	**CT 2**	**CT 3**	**PT 1**	**PT 2**	**PT 3**
Ratio:						
Type						

ID #:						
Serial #						
Use	☐ Indoor ☐ Outdoor	☐ Indoor ☐ Outdoor	☐ Indoor ☐ Outdoor	☐ Indoor ☐ Outdoor	☐ Indoor ☐ Outdoor	☐ Indoor ☐ Outdoor
Rated Primary volts						
Rated Primary amps						

Remarks:

Arizona Public Service Yearly Meter Reading and Bill Date Schedule
For 2000

	January		February		March		April		May		June		July		August		September		October		November		December	
Bill Cycle	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date	Read Date	Bill Date
01	12/29	01/05	01/28	02/04	02/29	03/06	03/29	04/04	04/28	05/04	05/30	06/05	06/28	07/05	07/28	08/03	08/28	09/01	09/27	10/03	10/27	11/01	11/29	12/05
02	12/30	01/06	01/31	02/07	03/01	03/07	03/30	04/05	05/01	05/05	05/31	06/06	06/29	07/06	07/31	08/04	08/29	09/05	09/28	10/04	10/30	11/02	11/30	12/06
03	01/03	01/07	02/01	02/08	03/02	03/08	03/31	04/06	05/02	05/08	06/01	06/07	06/30	07/07	08/01	08/07	08/30	09/06	09/29	10/05	10/31	11/03	12/01	12/07
04	01/04	01/10	02/02	02/09	03/03	03/09	04/03	04/07	05/03	05/09	06/02	06/08	07/03	07/10	08/02	08/08	08/31	09/07	10/02	10/06	11/01	11/06	12/04	12/08
05	01/05	01/11	02/03	02/10	03/06	03/10	04/04	04/10	05/04	05/10	06/05	06/09	07/05	07/11	08/03	08/09	09/01	09/08	10/03	10/09	11/02	11/07	12/05	12/11
06	01/06	01/12	02/04	02/11	03/07	03/13	04/05	04/11	05/05	05/11	06/06	06/12	07/06	07/12	08/04	08/10	09/05	09/11	10/04	10/10	11/03	11/08	12/06	12/12
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08	*01/08	01/14	02/08	02/15	03/09	03/15	04/07	04/13	05/09	05/15	06/08	06/14	07/10	07/14	08/08	08/14	09/07	09/13	10/06	10/12	11/07	11/13	12/08	12/14
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10	01/11	01/19	02/10	02/17	03/13	03/17	04/11	04/17	05/11	05/17	06/12	06/16	07/12	07/18	08/10	08/16	09/11	09/15	10/11	10/16	11/09	11/15	12/12	12/18
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13	01/14	01/24	02/15	02/22	03/16	03/22	04/14	04/20	05/16	05/22	06/15	06/21	07/17	07/21	08/15	08/21	09/14	09/20	10/16	10/19	11/15	11/20	12/15	12/21
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19	01/25	02/01	02/24	03/01	03/24	03/30	04/25	05/01	05/24	05/31	06/23	06/29	07/25	07/31	08/23	08/29	09/22	09/28	10/24	10/27	11/22	11/30	12/26	01/02
20	01/26	02/02	02/25	03/02	03/27	03/31	04/26	05/02	05/25	06/01	06/26	06/30	07/26	08/01	08/24	08/30	09/25	09/29	10/25	10/30	11/27	12/01	12/27	01/03
21	01/27	02/03	02/28	03/03	03/28	04/03	04/27	05/03	05/26	06/02	06/27	07/03	07/27	08/02	08/25	08/31	09/26	10/02	10/26	10/31	11/28	12/04	12/28	01/04

* Denotes SATURDAY Read Dates on 01/08 and 11/18.
04/21 is a Flex Holiday NOT scheduled for billing.

Read Date = Scheduled Read Date
Bill Date = Last Read Date / First Billing Date

Mt I ERING EQUIPMEN I PURCHASE ORDER

Purchaser Company	Date	D.O.E. # (if applicable)	
Address	City	State	Zip
Contact Name	Phone Number		

☐ Purchase Existing Equipment located at:

Customer Name	COOKIE COMPANY	UNI	0080399225512300001
Service Address	1224 TREAT STREET	Business Name	
Service City	SWEETS	Bldg/Unit	

Purchase: New Equipment ☐ Supplies ☐

☐ Ship To: ☐ Will Pick Up

Company Name	
Attn	
Address	
City, ST, Zip	

Qty	APN #	Description include meter # and serial # if applicable	Unit Price	Total
		EXISTING CURRENT TRANSFORMERS		265.10
			Sub Total	265.1
			Sales Tax	18.54
			Grand Total	**283.64**

Buyer has inspected the equipment and supplies and found them to be suitable for its purposes. Material is sold "as is, where is" and "with all faults" Seller makes no warranty, whatsoever, whether express or implied, concerning the equipment or supplies, or fitness thereof for any purpose, except that seller shall convey good title to buyer and that the product shall be delivered free from any lawful lien or encumbrance. Under no circumstances will seller be liable to buyer or any third party for lost profits or revenues, indirect, special, consequential, punitive or exemplary damages.

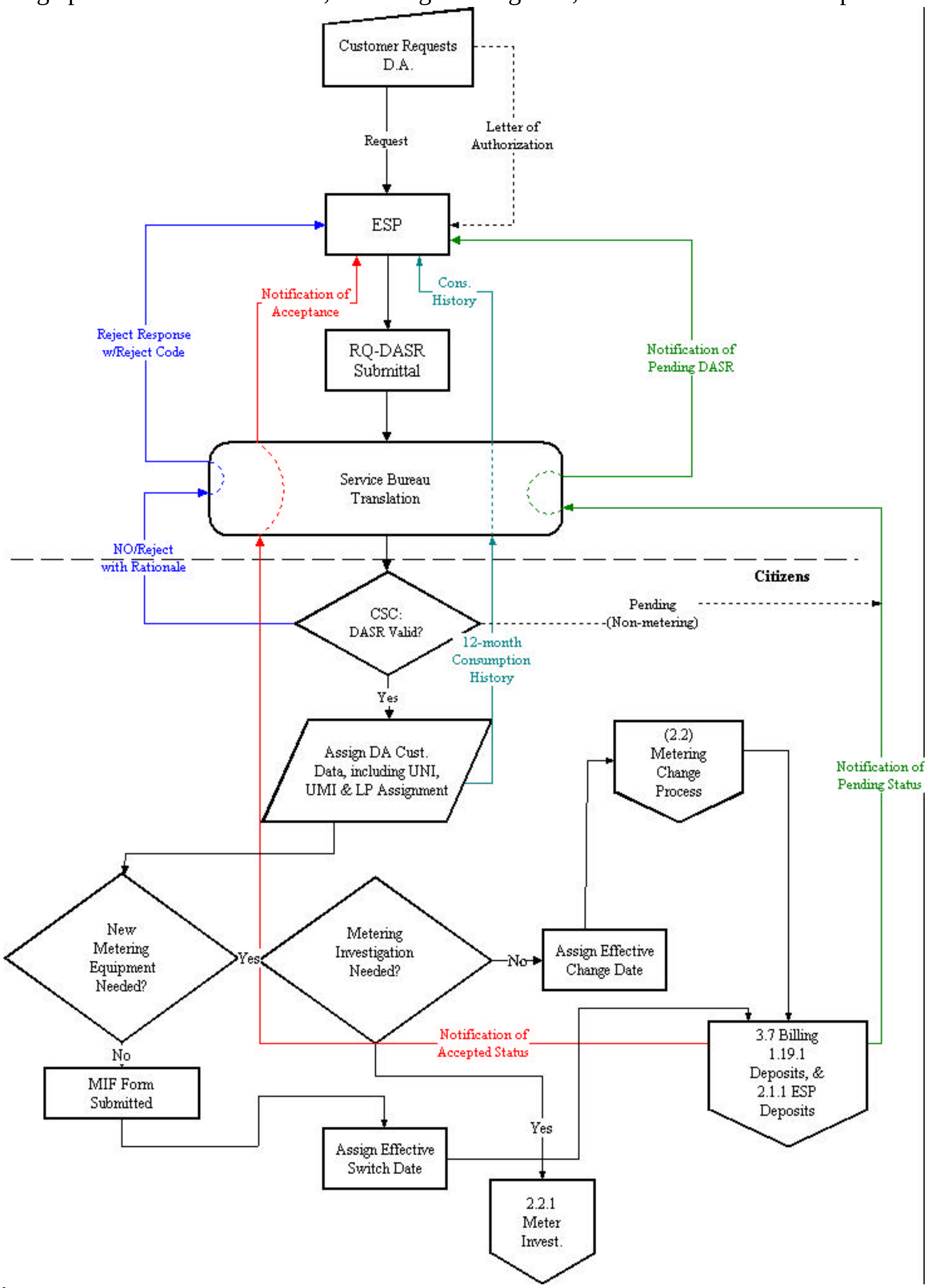
Buyer hereby assumes the risk of, and releases Seller from, and agrees to defend, indemnify and hold Seller, harmless, from and against, all claims, liabilities, tines, penalties, costs and expenses, including, but not limited to, those related to Buyer's own damages and losses and those of its customers, arising from or connected with, the possession, handling, processing, or use of the equipment or supplies by the Buyer or others, whether based on contract, negligence, or otherwise.

I have read the above disclaimer and understand its content and further agree to the terms and conditions set forth above.

BUYER	SELLER, Arizona Public Service Company
BY:	BY:
TITLE:	TITLE:
DATE:	DATE:

CITIZEN UTILITY COMPANY EXISTING CUSTOMER SIGNUP

Description: This process flow is intended to map the initial switch to a competitive service provider by a customer already connected to Citizens' distribution system. Customers new to CUC's distribution service territory are covered by Process 1.2, New Customer Sign-up. Customers already served by ESPs who seek to switch providers are covered by process 1.3, Switch Providers. The scope of this process spans the initial receipt of an RQ-DASR by Citizens, through hand-offs to the Billing and Meter Change processes. Process 2.2.1, Metering Investigation, is embedded within this process.



Discussion/Issues: The accompanying flow chart for this process is, by necessity, non-detail. There are a number of issues raised by this process which must be addressed within the next phase of an implementation program. Among them are:

- Scope and procure Service Bureau (SB) services
- Data interfacing between Service Bureau (SB) and Providers (ESP). The ACC's effort to push for the development of common Arizona EDI protocols is at least 6-18 months from fruition. In the mean time Citizens must be prepared to

accept and process DASRs, transmit and receive consumption history information, and post and retrieve metered data with ESPs, in some manner.

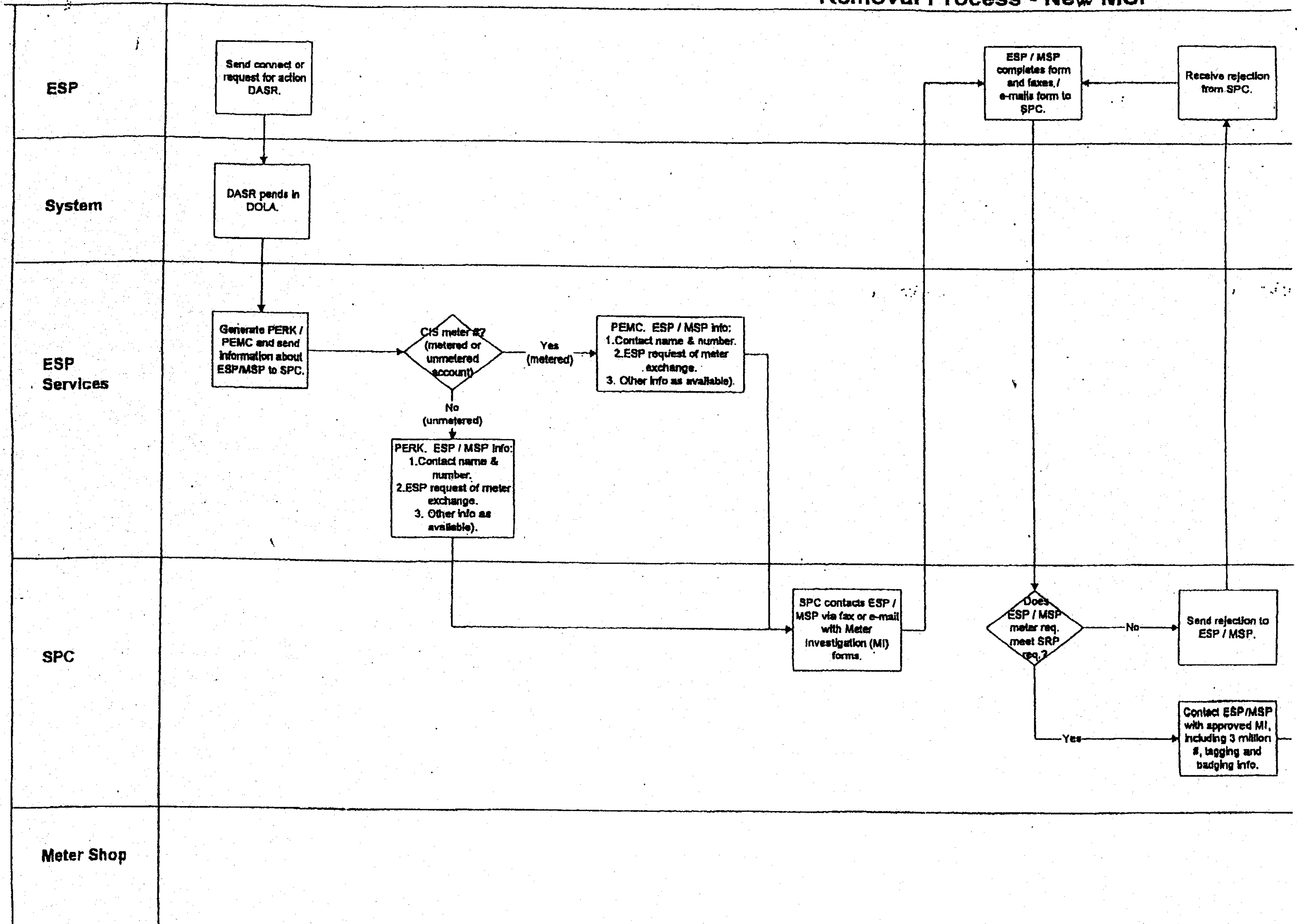
- Data interfacing between SB and Citizens. Data formats acceptable to CUC must be established and tested between the two entities.
- Assigning UNI – Citizens must develop a detail procedure for assigning universal node identifiers to individual distribution nodes. Citizens' current practice of identifying a specific node through their LID process appears to be adaptable to the UNI requirements of the Commission.
- Obviously, the Competitive Service Center (CSC) will need to be established and prepared to meet the objectives of receiving DASRs (in CUC format, from SB) and processing them.
- Citizens must develop new fields within, or workarounds to, their customer information system. New data such as ESP name, UNI, DALAS ID, Scheduling Coordinator, meter ownership, and probably others, must be tracked in some manner.
- Need a means to track submitted DASRs over time. This most likely should be scoped within the functions of the Service Bureau.
- Need tight guidelines for CSC to initiate a metering investigation and subsequent procedures for working with metering personnel. Mechanism to keep ESPs/MSPs informed of status.
- Need to develop fee structure for RQ-DASR submittals (as per Policy Decision 14, only will charge for Accepted RQ-DASRs)
- Consistent mechanism to assign effective switch dates when metering is involved.
- The means to process competitive data prior to the establishment of AZ standard EDI protocols, remains unclear. (CUC will not implement interim EDI prior to the establishment of these AZ standards in accordance with Policy Decision 10)
- Should CUC establish a MAC (meter activity coordinator)?

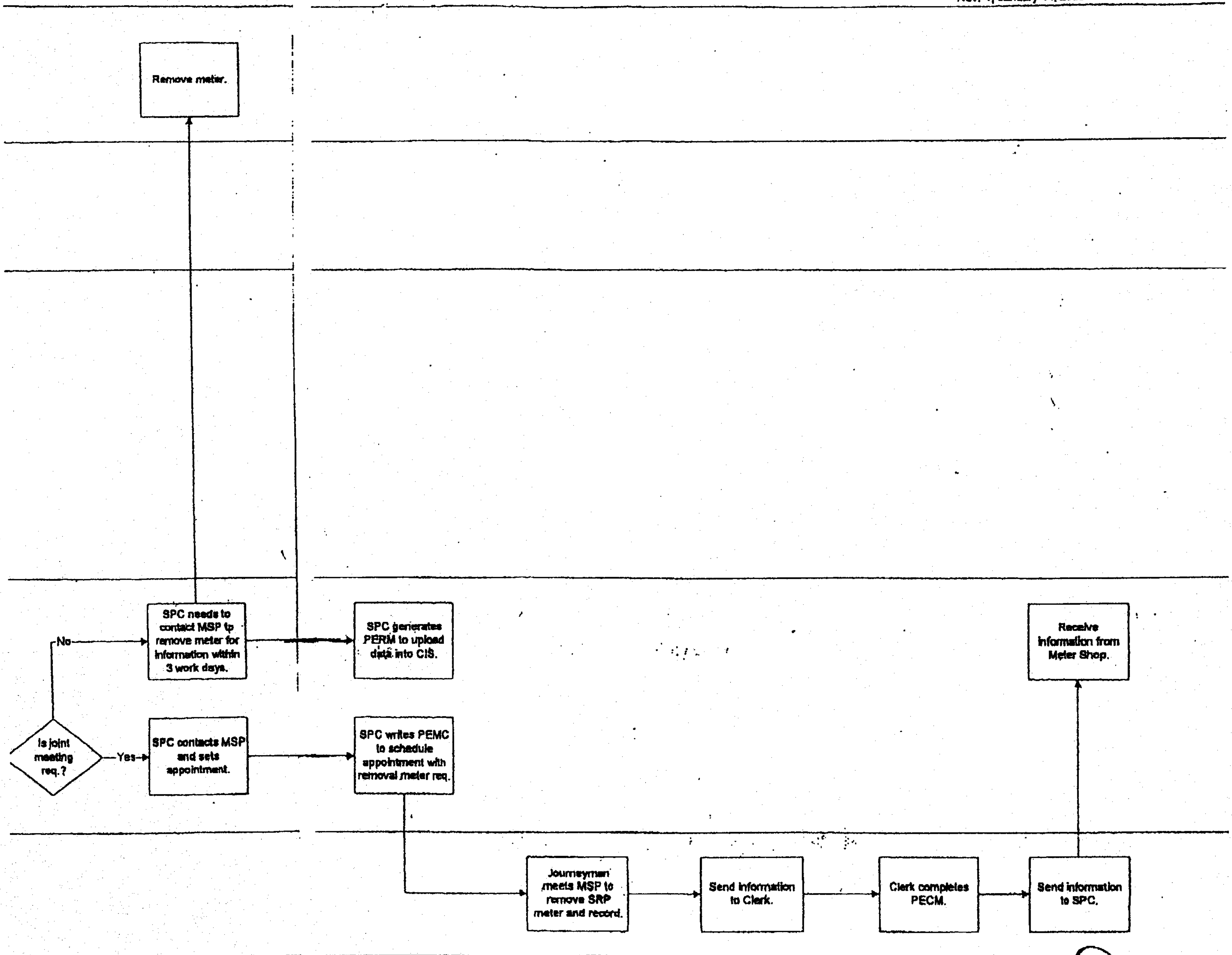
Next Steps:

1 Develop scope for SB services. Determine interim plan to meet near-term requirements prior to the development of AZ standard EDI protocols.
2 Scope the duties and responsibilities of CUC's CSC.
3 Work with IT to determine feasibility of adding required fields within existing IT systems cost and time effectively.
4 Develop UNI format and assignation process.
5 Determine requirements for DASR tracking and retention.
6 Determine fair, defendable fees for accepted DASRs that capture costs of all DASR processes.
7 Determine whether existing language on non-compliance is sufficient to address RQ-DASR hammering.
8 Develop rote procedure for CSC personnel to determine when metering investigations are required, and initiating the process with CUC metering personnel
9 Develop fair guidelines for assigning an Effective Switch Date for meter requirements customers.
10 Assure Terms and Conditions delineate RQ-DASR fee decisions.
11 Develop all appropriate form letters, notices, etc.
12 Develop DASR validation rules.

Appendix M-3.3

Meter Exchange ... Removal Process - New MSP





PRODUCTIVITY CONSULTING

DASR #
Meter of

SRP

Delivering more than power™

Date of Issue:

Meter Investigation (MI)

Meter No.		ML:		RI:	
Customer Name:		SRR:			
Address:		Alternate Phone:			
Home Phone:		DA Ready (Y/N):		Joint Meet (Y/N):	

Meter Information

MFG.		Meter Voltage		W		Ph		TA		Kh		Dials	
Model		Form		Register Ratio				Multiplier					
Class		Char: S/D/Y/N		Service Voltage				No. of CT's/Ratio					
IDR (Y/N)		KYZ Output		Billing Multiplier				No. of PT's/Ratio					
Communications (Modem / RF / etc):				Module No.									
Next 3 Read Dates						Tariff Rate:		Program ID					

Meter Investigation Response

Option 1 SRP Installs Meter **(Y/N):**		***OR*** *Option 2* ESP Installs Meter **(Y/N):**	
A) SRP Provided Metering **(Y/N):** ***OR*** ***B)*** ESP Provided Metering **(Y/N):**		***Fee for Non - Returned Meters $300***	
Meter Type **Tariff Rate:** **Basic Choice** ~ Load Profile (LP) **(Y/N):** **Premium Choice** ~ LP w/ Communications **(Y/N):** **Module No:** **(Modem / RF / etc):**		Meter Must Be Returned Within 5 Days After Install Date	Return SRP Meter To:
Meter Must Be Received 6 Days Prior to Install Date	Ship ESP Meter To:	Meter Installation Record Must Be Received Within 2 Days After Install Date	Send SRP Meter Record To:
Joint Meet Required **(Y/N):** Joint Meet Time / Date:			

Meter Ownership Changes

New **ESP** Name and Address		New **MSP** Name and Address	
DUN No.		DUN No.	

For More Information:

Phone: (602) 236-4720 e-mail: prbarstad@srp.gov Fax: (602) 236-4703

SRP *MI* Form Vs 2.1, October, 27, 1998

DASR #	
Meter #	

SRP

Delivering more than power™

Date of Issue:	

Exchange / Removal / Read

Service Request Information

Request Received By:	Requested By:	Service Requested / Comments

Account Information

Meter Number:		Tariff Rate:		PRG ID	
Billing Cycle Days	Next 3 Read Dates			IDR (Y/N):	
Customer Name:		ML:		RI:	
Address:		SRR:			
Home Phone:		Alternate Phone:			

Completed Service Request Information

Off Reads for Removed Meter Date of completion:

KWH:	KW:	8:	0:
1:	2:	3:	4:
5:	6:	7:	8:
9:	10:	11:	12:

Removed Meter Information

Meter Number					
Form		Volts		CT Ratio	
Dials		Mult		PT Ratio	
Billing Multiplier		KYZ Output			
IDR		Tariff Rate		PRG ID	
Module No.		Modem / RF/ etc:			

Installed Meter Information

Meter Number					
Form		Volts		CT Ratio	
Dials		Mult		PT Ratio	
Billing Multiplier		KYZ Output			
IDR		Tariff Rate		PRG ID	
Module No.		Modem / RF/ etc:			

Comments:

Please inicate any chanes to the following:

ML		RI	
SRR			

DASR #	
Meter	of

Acknowledgment Date:

Delivering more than power™

SRP Acknowledgment Form

Meter No.			ML:		RI:	
Customer Name:		SRR:				
Address:		Alternate Phone:				
Home Phone:		DA Ready (Y/N):		Joint Meet (Y/N):		
Billing Cycle:	Days	Next 3 Scheduled Read Dates:				

SRP Acknowledges the Following Selections For This Account

Option 1 SRP Installs Meter **(Y/N):**	***OR***	***Option 2*** ESP Installs Meter **(Y/N):**	
A) SRP Provided Metering **(Y/N):** ***OR*** ***B)*** ESP Provided Metering **(Y/N):**		***Fee for Non - Returned Meters $300***	
Meter Type **Tariff Rate:** **Basic Choice** ~ Load Profile (LP) **(Y/N):** **Premium Choice** ~ LP w/ Communications **(Y/N):** **Module** **(Modem / RF / etc):** **No:**		Meter Must Be Returned Within 5 Days After Install Date	Return SRP Meter To:
Meter Must Be Received 6 Days Prior to Install Date	Ship ESP Meter To:	Meter Installation Record Must Be Received Within 2 Days After Install Date	Send SRP Meter Record To:
Joint Meet Required **(Y/N):**	Joint Meet Time / Date:		

Comments

SRP ***A*** Form Vs 2.1, October, 27, 1998

Date of Issue:

Delivering more than power™

Direct Access Meters

(for SRP use)

Meters Owned by:

MSP Name and Address		ESP Name and Address	
DUN No.		DUN No.	

Meter Information

Total Number of Meters:

Beg Meter No.		Ending Meter No.	
Beginning Serial Number		Ending Serial Number	
Beg Module No.	Communications type (Modem / RF/ ect)		Ending Module No.
Manufacturer		Register Ratio	
Model		AEP Standard Code	
Class		Pulse P/R	
Form		Optical Port (Y/N)	
Meter Voltage		Remote Optical Port (Y/N)	
Wire		Program ID	
Phase		KWH (Y/N)	
Test Amps		KW (Y/N)	
Meter Kh		KVARH (Y/N)	
Programmed Kh		KVAR (Y/N)	
Dials		TOU (Y/N)	
Multiplier		IDR (Y/N)	
Interval Data			
# of Channels:	Interval Length:	Memory Size:	K
Demand Data			
Interval Length:	Full Scale Maximum Demand:		

Comments

TEP DASR REQUEST

Direct Access Meter Exchange

All customer/ESP requests for Direct Access shall be made on an RQ DASR Form as set forth in TEP's Direct Access Service Request Protocol. A properly completed DASR Form must be accepted by TEP prior to the provision of Metering Services. Meter exchanges must be scheduled at least five days prior to regular read date.

ESP Chooses Ownership Option

If a Direct Access customer desires to own their meter, the customer's ESP must so indicate in the Field 44 on the customer's RQ DASR. TEP will thereafter send a partially completed MI Form to the ESP via e-mail or facsimile. Upon request, the ESP is required to complete the MI Form, including an indication of the party who is to own the meter. More specifically, the ESP must indicate one of the following ownership and installation options:

a. The ESP purchases and owns a TEP-provided and installed meter (if adequate competition is not available, see Section 6.2).
b. The ESP provides and owns the meter that TEP installs (if adequate competition is not available, see Section 6.2).
c. The ESP provides and owns the meter that an MSP other than the ESP installs.
d. The ESP provides, the customer owns and an MSP other than the ESP installs the meter.

ESP Provides 1 of 3 Options

ESPs may provide Metering Services to Direct Access customers by any of the following methods:

a. Becoming a certified MSP in accordance with ACC Certification Qualifications
b. Subcontracting with a third-party MSP certified in accordance with ACC Certification Qualifications
c. If no certified MSPs are available in the area, subcontracting with TEP

Provision of Metering Services

In providing Meter Services hereunder, ESPs and/or their representative MSPs must provide TEP with an MA Form for any meter installed, within five business days of the installation. The MA Forms shall be provided to the TEP Meter Shop by e-mail or facsimile.

Installed Meters Standard Requirements

Any IDR meters installed by an MSP or ESP shall comply with the interim minimum standards and testing requirements for meters and metering equipment used in Direct Access metering. All meters and metering equipment must further comply with the following standards, which are contained in the American National Standards Institute ("ANSI") standards publication.

Direct Access Meter Identification

Each ESP is responsible for sealing its meters. The ring seal for each meter shall be orange and contain a mark unique to that ESP or the ESP's agent. ESPs requiring assistance ordering such seals may contact the TEP Meter Shop at (520) 745-3176, which will make an initial quantity of orange seals available.

TEP Installation of Equipment for ESPs and End-Use Customer Meters

Direct Access customers with single premise demands greater than 20 kW or 100,000 kWh annually will be required to have in place Interval Metering at no expense to TEP. Interval Metering is optional for those customers with annual demands of 20kW, 100,000 kWh or less. Any such meter/recorder must be included on the list of TEP-approved meters. In the event an MSP is not available, TEP will install such meter and associated equipment at the ESP's expense. To ensure timely installation in such case, the meter and associated equipment must be provided to the TEP Meter Shop five business days prior to the install date. If the ESP requests that TEP also program the meter, the ESP must provide TEP with program specifications. If TEP is to serve as the MRSP, the method of programming must be agreed to by TEP to ensure TEP has the ability to read the meter. The ESP may elect to use an alternative MRSP if one becomes available after the meter has been installed by TEP.

Scheduling Joint Meets

TEP will charge the ESP for time and materials for a joint meet requested by the MSP, not otherwise required by TEP. All services, equipment and material requested by an MSP must be listed in detail on an MPIA Form and returned to the Meter Shop via mail, e-mail or facsimile at the addresses or facsimile number listed in Section 7 herein. Thereafter, TEP will return detailed and total estimated costs to the requesting ESP for signature approval and return to the Meter Shop.

A joint meet must be scheduled at least five business days prior to any meter exchange date. A desired joint meet date and time shall be indicated by the ESP on an MI Form before it is returned to TEP. The Meter Shop will send a confirmation of the joint meet to the ESP and MSP. In the event the MSP wishes to cancel a scheduled joint meet, TEP requires one business day notice to avoid charges. TEP will schedule appointments for joint meets between 8:00 a.m. and 3:30 p.m., Monday through Friday.

Final Reads

When a TEP meter is removed and a new Direct Access meter installed by an MSP, the final read of the removed meter must be provided, consistent with meter type, to TEP within three business days of the new meter installation. When the meter to be removed is a TEP IDR meter, the MSP shall notify TEP of the planned removal on an MA Form no less than five business days prior to removal. Thereafter, TEP will read and interrogate the meter prior to its removal. TEP will provide an MA Form to complete this transaction. For TEP owned non-IDR meters being removed, the ESP shall obtain a final read which it shall remit to TEP within three days of said removal.

Returning TEP-Owned Meters and Equipment

Removed TEP-owned meters and/or equipment (CTs and VT's) shall be returned to TEP within 15 days of removal in the same condition the meter was in prior to removal. If a removed meter is not delivered to TEP within 15 days of removal or is returned damaged, TEP will charge the ESP for the cost of the meter and metering equipment and/or any other changes pursuant to the applicable ACC-approved tariff.

Meter Test History

All ESPs and MSPs shall make all meter test history available to TEP. Both "as found" and "as left" test data shall be recorded by the ESP and/or MSP per ACC rules. Annual reports shall be provided to the ACC as required for all meters removed from service.

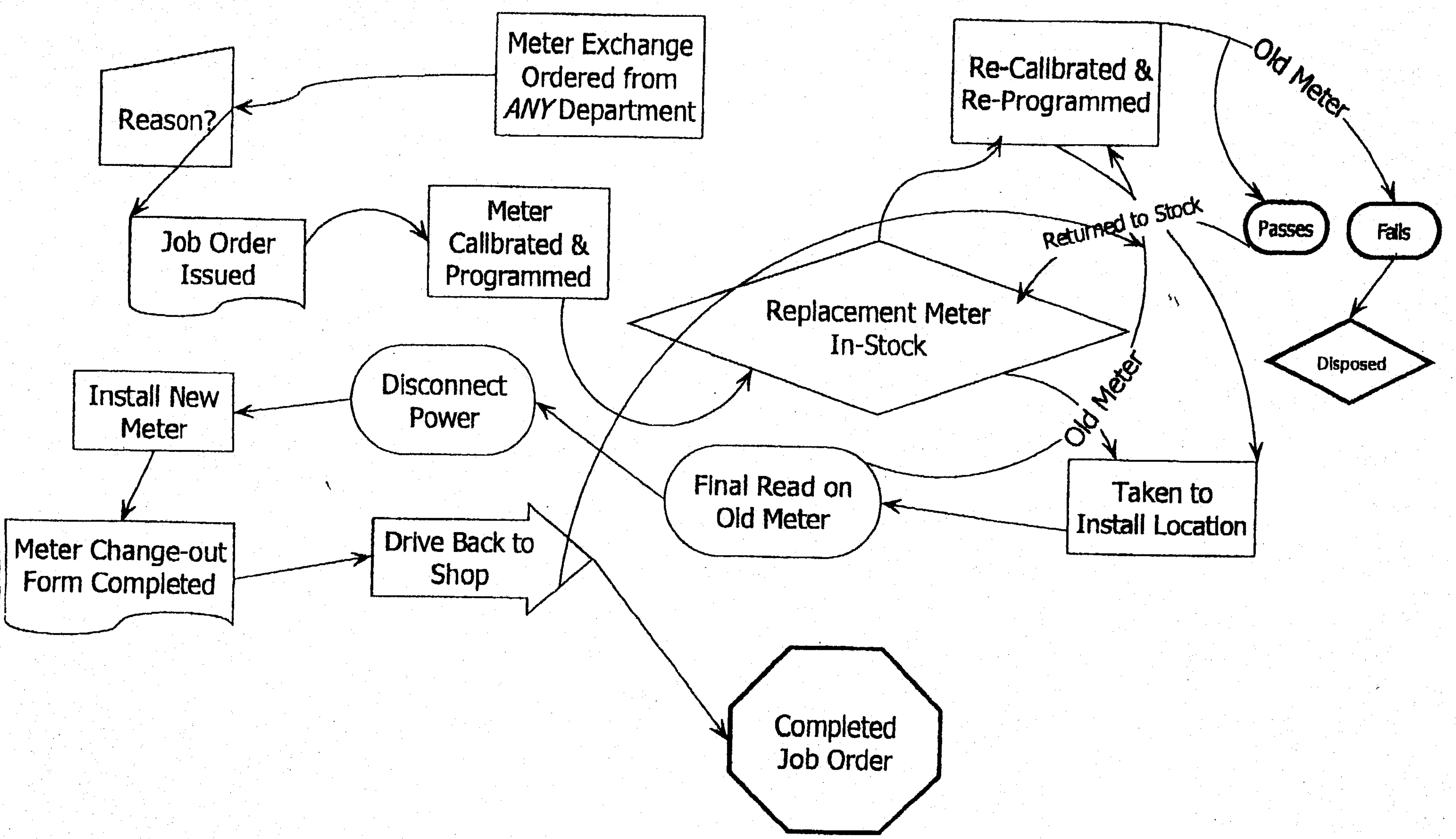
Telephone Lines and Meter Modems

The MSP shall be responsible to verify the actual meter modem connection to the customer or ESP-supplied telephone line. The telephone connection must be safe, secure and in operation while the MSP is on location at the service point. The MSP shall contact the MRSP to verify adequate telephone service.

Security Management

TEP will not provide metering programming passwords or software to other entities for TEP-owned meters. TEP will not require ESPs to provide programming passwords or software for their meters. In the event of a meter reading audit, the ESP shall provide proof to TEP that the meter is programmed correctly and registering accurate usage. TEP reserves the right to inspect any service point in its Service Area. If any corrections are necessary, TEP will notify the responsible ESP.

Trico's Residential Meter Change-Out



Meter Data Comparison
Bundled Customer (meter exchange required) to Direct Access

STEP #1 **Data from the Enrollment DASR**

Data Element	Size	Type	TEP	SRP	APS		
Data Elements begin with Step #2							

STEP #2 **Metering Information from UDC to MSP/ESP (Existing Meter Information EMI)**

Data Element	IG Loc.	UIG	TEP (Current)	SRP (Current)	APS (Current)	AZ Ideal Data Elements Required = R Conditional = C Optional = O	CUBR
Customer name	H050 N102	O	X	X	X	R	R-H050 N102
Service address	H070 N3	O	X	X	X	R	R-H070 N3
Business Name (DBA)					X	C – used if data available – (3-15-00 UDCs recommend keeping this field)	
Mailing Address						Delete	
Customer Phone				X		Delete	
Building/Unit					X	Delete	
Service city/town/county	H070 N4	O	X	X	X	R	R-H080 N4
Date EMI sent	H020 BGN03	R	X	X	X	R	R-H020 BGN03
UDC Account Number						R	
Existing meter number	D030 REF02	O	X	X	X	R	R-D030 REF02
Universal Node Identifier (UNI)			X		X	R (3-15-00 CUBR uses SDPI as their UNI)	
DASR Tracking Number			X	X		C – may not be used for all metering scenarios. (3-15-00 We believe that CUBR is using this field with a different field name)	
UDC name						R	
ESP name	H050 N102	O	X		X	R – while paper forms are used Janie suggested using ticker symbol for name (NEW, APSES, etc) (3-15-00	O-H050 N102
ESP DUNS	H050 N104	O	X			R – when electronic format is used –EDI 650, CSV	O-H050 N104
ESP email	H090	O	X			Delete	

	PER						
MSP name	H050 N102	O	X		X	R – while paper forms are used (3-15-00 This is conditional for CUBR since they send meter data out as requested on their 814 which could have no tie to an MSP. For this AZ scenario we MUST know who the MSP is thus a required field.)	C-H050 N104
MSP DUNS	H050 N104	O				R – when electronic format is used – EDI 650, CSV (3-15-00 Same as MSP Name)	C-H050 N104
Scheduling options					X	Delete	
*Install Meter (new service)					X	Delete	
*Exchange Meter					X	C (3-15-00 Changed this field from R to C – We don't know if CUBR uses this type of field.)	
*Upgrade Meter						C (3-15-00 Changed this field from R to C - We don't know if CUBR uses this type of field.	
Read cycle number	D030 REF02	O	X		X	R (3-15-00 Conditional(CUBR) – if meter read is based on a cycle)	C-D030 REF02
ESP requested change date			X		X	Delete	
Site meet required (y/n)	D070 YNQ09	O	X	X	X	R (reasons for site meet may vary within service territories) (3-15-00 CUBR has this in step 3 but not the MI)	
Current owner of Meter	D030 REF02	O			X	Delete (3-15-00 CUBR has it as a required field for	R-D030 REF02

							other scenarios i.e. ESP to ESP switch.	
Current owner of ITs			X		X		Delete	
Totalized/Combined Metering (y/n)			X		X		R (3-15-00 CUBR doesn't have this field but they DO handle totalized/combined in the HL segment)	
Associated equipment purchase authorization/information (y/n)			X		X		R (3-15-00 CUBR does not have this field -- Changed Associated purchase order to Associated purchase authorization/information)	
Medical Monitoring (y/n)	D030 REF02	O			X		R	R-D030 REF02
Voltage, electrical, special monitoring Equipment			X		X		Delete – this information will appear in Remarks area of document	
Order type					X		Delete	
Data Element	IG Loc.	UIG	TEP	SRP	APS		Ideal Data Elements Required = R Conditional = C Optional = O	
*Install Meter (install of new meter)					X		Delete – it appears above	
*Exchange Meter (exchange of existing meter)					X		Delete – it appears above	
Existing meter owner	D030 REF02	O			X		Delete (3-15-00 CUBR has it as a required field for other scenarios i.e. ESP to ESP switch. **When we get to the other scenarios we will not want both Current and Existing meter owner as CUBR has.)	R-D030 REF02
Existing meter Universal Meter Identifier (UMI)			X				Delete	C-D030 REF02
Existing meter serial number	D030	O			X		Conditional–	O-D030

	REF02						SRP may not have serial numbers assigned to all meters	REF02
Existing meter model/type	D030 REF02	O	X	X	X	R	O-D030 REF02
Existing meter register model/type	D030 REF02	O			X	Delete	O-D030 REF02
Existing meter form number	D030 REF02	O	X	X	X	R	O-D030 REF02
IDR meter (y/n)						R	
IDR number of channels	D030 REF02	O	X	X	X	Delete – based on meter type (3-15-00 CUBR doesn't have this field but they DO handle device info in the YNQ segment)	
Test amps	D100 MEA03	O	X	X	X	Delete Pending Delete Conditional(CUBR) Required if available	C-D100 MEA03
Service voltage						R – Conditional(CUBR) – Required if available	C-D100 MEA03
Meter voltage	D100 MEA03	O	X	X	X	R	R-D100 MEA03
Existing meter disk constant (Kh)						R	
Existing meter pulse constant (Ke)	D100 MEA03	O	X	X	X	Conditional Conditional(CUBR) – Required if available	C-D100 MEA03
Existing meter register constant (Kr)	D100 MEA03	O	X	X	X	Conditional	R-D100 MEA03
Existing dial constant (meter multiplier)						R	
Pulse Output			X		X	Delete (3-15-00 CUBR uses Disc Constant Ke rather than Pulse Output and defines the	

						ratio in the KYZ Output field)	
CT ratio	D030 REF0 2	O	X	X	X	Conditional – required if CTs are present	O-D030 REF02
CT type					X	Conditional	
CT id number (s)					X	Conditional	
CT serial number (s)					X	Conditional	
VT ratio	D030 REF0 2	O	X	X	X	Conditional – required if VT present	O-D030 REF02
VTtype					X	Conditional	
VT id number (s)					X	Conditional	
VT serial number (s)					X	Conditional	
Remarks	D250 MTX0 2	O			X	Conditional – this field will be used to specify voltage monitoring , special or electrical monitoring equipment (3-15-00 CUBR does not have a remarks field) On customer accounts located in rural areas, some site information may be included in this field.	
Program ID			X	X		Delete (3-15-00 CUBR may be using this for other scenarios. No appropriate use of this field identified for AZ)	O-D030 REF02
Communications (modem) Module No.	D030? ? REF0 2	O		X		Delete	
KYZ Output	D030 REF0 2	O	X	X		Conditional – if pulse exists, it will be supplied (3-15-00 Possible discrepancy with CUBRs use of Optional since Disc Constant it Conditional)	O-D030 REF02
Current Tariff Rate	D030 REF0	O	X	X		Required The current rate	R-D030 REF02

	2					the customer is on will be sent.	
Meter Class	D100 MEA03	O	X	X		R	R-D100 MEA03
Read Dates (3)			X	X		Delete	
Register Ratio	D100 MEA03		X	X		Conditional – depends on meter type	C-D100 MEA03
Characteristics (Delta/Wye/Network)	D030 REF02	O	X	X		R (CUBR calls it the Phase connecting/transformer configuration – Figures are D or W)	C-D030 REF02
Phase	D100 MEA03	O	X	X		Delete We feel this information is represented in the form number field. This is redundant information.	R-D100 MEA03
Wires	D100 MEA03	O	X	X		R	R-D100 MEA03
Number of Dials	D100 MEA03	O	X	X		Delete (Discussion point – does this need to be given in step #2)	R-D100 MEA03
Special Read Remarks (type of meter)			X	X		Delete	
Meter Location (where meter can be found)	D250 MTX02	O	X	X		Conditional – if information is present it will be provided	C-D250 MTX02
Read Instructions (special instructions for reading meter)	D250 MTX02	O	X	X		Conditional – if information is present it will be provided	C-D250 MTX02
DA Ready (SRP service territory)				X		Conditional – if UDC allows for ESP to buy metering	
Purchase Date	D050 DTM	O	X			Delete	
Return of equipment			X	X		Delete	
KVARH Metering required (y/n)						R (this indicated whether kvarh is required)	YNQ~~N~9~ KVARH
Transaction reference number		R				R - This would	R-H020

						be valuable for use in the MADEN and in the future for the 824.	BGN02
Refers to LIN01 of 814???						Delete – This is DASR tracking number	C-H0120 BGN06
Communications owner						Conditional	R-D030 REF02
Cell phone for communications(y/n)						R	R-D070 YNQ01
Transformer loss compensation (y/n)						R	R-D070 YNQ01
Phone line dedicated(y/n)						R CUBR – Is required but what if there is no phone?	R-D070 YNQ01
Meter Phone Number						Conditional	
Shared Phone Line (y/n)						R	
XFMR Rating factor						C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	
XFMR Accuracy Class						C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	
XFMR BIL (basic installation level)						C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	
Radio communications (y/n)						R	
# of meters for site						R	

STEP #3 Scheduling Information from MSP/ESP to UDC (Meter Data Communication Request MDCR)

Data Element	IG Loc.	UIG	TEP	SRP	APS	-Ideal Data Elements Required = R Conditional = C Optional = O	CUBR
Date MDCR Sent						R (4-10 added)	
Transaction Number						R (4-10 added)	
DASR #						R	
MSP Contact Person					X	Delete R	
MSP Phone Number					X	Delete R	
Site meet required (Y/N)	D070 YNQ 01	O	X	X	X	R	R-D070 YNQ01
Scheduled Date (scheduled installation date)	D050 DTM	O	X		X	R	R-D050 DTM02
Site meet time			X	X	X	Conditional – If MSP or UDC request site meet, additional coordination is required. The method to confirm site meet date and time may be the use of MADEN or some other exception notice. We would like to keep this for a manual process (forms). A spreadsheet may be needed in the future for when the transaction moves to EDI650.	
ESP Name						R	
Sender Name (UDC/MSP)						R (4-10 Changed from MSP Name to Sender since this form will be used in other scenarios)	
Receiver Name (UDC/MSP)						R (4-10 Changed from MSP Name to	

						Receiver since this form will be used in other scenarios)	
Pending owner of meter (specific Company or Customer Name)	D030 REF 02	O			X	R	R-D030 REF02
*Name			X	X		Delete	
*Address			X	X		Delete	
*DUNS (optional)				X		Delete Required(CUBR) – If customer, use “customer” We may want to use this for an electronic format (EDI 650)	R-D030 REF03
Pending owner of ITs (specific Company or Customer Name)					X	R (In AZ the CT & PTs are sold)	
Purchase existing ITs (y/n)			X		X	R (In AZ the CT & PTs are sold)	
Purchase existing totalized/combined equipment (y/n)					X	R (In AZ the CT & PTs are sold)	
Purchaser of existing CT/PT (VT) *ESP					X X	Delete	
*MSP					X	Delete	
*Customer					X	Delete	
Pending Owner of totalized/combined equipment					X	Delete	
*ESP					X	Delete	
*MSP					X	Delete	
*Customer					X	Delete	
Remarks	D250 MTX 02	O			X	Optional	
Installer (UDC or MSP)				X		Conditional – SRP can perform these services Required(CUBR) DUNS or DUNS+4	R-D030 REF03
Communications to be installed (modem type, phone line installation)			X	X		Conditional – SRP can provide MRSP services	O-D030 REF02
ESP Provided Meter Manufacturer			X			Delete (This information will be provided on the MIRN form)	R-D190 NM1
Meter Type	D030 REF 02	O	X			Delete (This information will be provided on the MIRN form)	
Form Number	D030 REF 02	O	X			Delete (This information will be provided on the MIRN form)	O-D030 REF02

IDR Type			X			Delete	
Customer name						R Required(CUBR)	R-H050 N102
Customer account number assigned by ESP						Delete Is required(CUBR) if currently customer of ESP	O-H100 N102
Service Address						R	
City/Town/County						R	
Customer account number assigned by UDC						R	R-H100 N102
Service delivery point (UNI number in Arizona)						R (CUBR) – Required if available	C-D030 REF03
Schedule Notification Type						R (this is to indicate what type of notification the MSP is scheduling)	
Meter number						R	R-D030 REF02
Current meter owner (DUNS or DUNS+4)						Delete Required(CUBR) – If customer, use “customer”	R-D030 REF03
Site meet REQUESTED (Y/N)						Delete for form use (CUBR) – distinguishes between required/requested this is for EDI 650 use.	R-D070 YNQ01

STEP #4 Meter Information from MSP/ESP to UDC (Post Meter Exchange) (Meter Installation/Removal Notification MIRN)

Data Element	IG Loc.	UIG	TEP	SRP	APS	Ideal	CUBR
Date MIRN sent						R (This is for form use only)	R-H020 BGN03
UDC & DASR Reference Number						R	
Work completion date	D050 DTM	O	X	X	X	R	R-D050 REF02
Time work completed	D050 DTM	O	X		X	R Conditional(CUBR) Required for interval meters.	C-D050 REF03
Meter Exchange/Meter Removal/Meter Re-program						R	
Customer Name						R	
Service Address						R	
Business Name						R	
City/Town/County						R	
UDC account number						R	
UNI Universal Node Identifier						R	
Existing Meter number						R	
Existing Meter serial number							
Existing Kvarh meter number						C	
Existing Kvarh serial number						C	
ESP						R	
MSP						R	
New meter owner	D030 REF 02	O			X	Delete (this appears on the MDCR)	R-D030 REF03
New meter number	D030 REF 02	O		X	X	R	R-D030 REF02
New meter UMI					X	Delete	C-D030 REF02
New meter serial number	D030 REF 02	O			X	R	O-D030 REF02
New meter model type	D030 REF 02	O			X	R	R-D030 REF02
New meter register model/type	D030 REF 02	O			X	Delete	O-D030 REF02
New meter form number	D030 REF 02	O		X	X	R	O-D030 REF02
New meter test amps	D100 MEA 03	O			X	Delete Pending Delete Conditional(CUBR) - Required if available	C-D100 MEA

New Kvarh meter number						C	
New Kvarh serial number						C	
Service voltage						R Conditional(CUBR) – Required if available	C-D100 MEA
New meter voltage	D100 MEA 03	O		X	X	R	R-D100 MEA03
New meter disk constant (Kh)						R	C-D100 MEA03
New meter pulse constant (Ke)	D100 MEA 03	O			X	Conditional Conditional(CUBR) – Required if available	C-D100 MEA
New meter register constant (Kr)				X	X	Conditional – required if available	R-D100 MEA03
New dial constant (meter multiplier)						R	
New meter KYZ Output	D030 REF 02	O		X	X	Conditional – if pulse exists	O-D030 REF02
Most recent calibration test date					X	R	R-D050 REF02
Test – full load			X	X		Delete This can be requested as needed.	
Test – light load			X	X		Delete This can be requested as needed.	
Test – Power Factor			X	X		Delete This can be requested as needed.	
# of IDR Channels			X	X	X	R	
Existing Meter Date						Conditional – based on meter type	
Existing Meter Time						Conditional – based on meter type	
Type of Interval Data Recorder						Delete	
Existing hard dial meter read (kWh)			X	X	X	Conditional – depending on meter type	C-D100 MEA
Existing hard dial meter read (kW)			X	X	X	Conditional – depending on meter type	C-D100 MEA
Existing hard dial meter read (kvarh)						Conditional	C-D100 MEA

Existing TOU read (on peak) kWh						Delete Conditional	
Existing TOU read (on peak) kW						Delete Conditional	
Existing TOU read (off peak) kWh						Delete Conditional	
Existing TOU read (off peak)kW						Delete Conditional	
Existing TOU read (shoulder peak) kWh						Delete Conditional	
Existing TOU read (shoulder peak) kW						Delete Conditional	
Existing TOU Read Display # (1-12)						Conditional – depending on meter type	
Existing TOU Read (1-12)						Conditional – depending on meter type	
Existing meter read display 01			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 02			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 03			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 04			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 05			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 06			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 07			X	X	X	Delete Conditional – depending on meter type	
Existing meter read display 08			X	X		Delete Conditional – depending on meter type	
Existing meter read display 09			X	X		Delete Conditional – depending on meter type	
Existing meter read display 10			X	X		Delete Conditional – depending on meter type	

Existing meter read display 11			X	X		Delete Conditional – depending on meter type	
Existing meter read display 12			X	X		Delete Conditional – depending on meter type	
New meter read (kWh)	D100 MEA 03	O	X		X	R	
New meter read (kW)	D100 MEA 03	O	X		X	Conditional	
New meter read (kvarh)	D100 MEA 03	O				Conditional	
Return of equipment (Ship or deliver)					X	Delete	
New TOU Read Display # (1-12)						Conditional – depending on meter type	
New TOU Read (1-12)						Conditional – depending on meter type	
New meter display sequence – kWh			X		X	R	
New meter display sequence – kW			X		X	Conditional	
New meter display sequence - kvarh						Conditional	
New meter number of dials – kWh	D100 MEA 03	O			X	Required	R-D100 MEA
New meter number of dials – kW	D100 MEA 03	O			X	Conditional	R-D100 MEA
New meter number of dials – kvarh	D100 MEA 03	O				Conditional	R-D100 MEA
New meter display decimal value – kWh					X	Delete	
New meter display decimal value – kW					X	Conditional	
New meter display decimal value – kvarh					X	Delete	
Condition of returned meter	D250 MTX 02	O			X	Delete – If the meter is damaged, this information can be displayed in the Remarks field.	
Condition of returned CT/VT					X	Delete	
Remarks (comments)	D250 MTX 02	O	X	X	X	Optional	
Tariff Rate	D030 REF 02	O	X	X		Delete	R-D030 REF02

Module Number				X		Delete	
Billing Multiplier				X		Delete	
CT ratio (this is for new MSP equipment only)	D030 REF 02	O		X	X	C - In Arizona, MSPs can set their own CT/VT	
CT type (this is for new MSP equipment only)					X	C	
CT id number (s) (this is for new MSP equipment only)					X	C	
CT serial number (s) (this is for new MSP equipment only)					X	C	
CT Use (indoor vs. outdoor) (this is for new MSP equipment only)					X	C	
VT ratio (this is for new MSP equipment only)				X	X	C	
VT type (this is for new MSP equipment only)					X	C	
VT id number (s) (this is for new MSP equipment only)					X	C	
VT serial number (s) (this is for new MSP equipment only)					X	C	
VT Use (indoor vs. outdoor) (this is for new MSP equipment only)					X	C	
Rated primary volts (this is for new MSP equipment only)					X	C	
Rated primary amps (this is for new MSP equipment only)					X	C	
KYZ Output	D030 REF 02	O	X	X		Delete – duplicated field.	
Program ID	D030 REF 02	O	X	X		Conditional – if SRP is reading meter	O-D030 REF02
Special Read Remarks	D250 MTX 02	O	X	X		Delete – This information will be supplied in Read Instructions. Conditional(CUBR) – Required if available	C-D250 MTX02
Meter Location	D250 MTX 02	O	X	X		Conditional – if access changes were made by MSP	C-D2550 MTX02
Read Instructions	D250 MTX 02	O	X	X		Conditional – if access changes were made by MSP	C-D2550 MTX02
Utility’s previous account number						Delete Conditional(CUBR) – Ifchanged in past 90 days	C-H100 REF02
Service delivery point ID						Delete – this is signified by the UNI number in AZ. Conditional(CUBR) – Required if available	C-D030 REF02

Utility rate subclass						Delete Conditional(CUBR) – Required if available	C-D030 REF02
Communications owner						Delete	R-D030 REF02
Date device manufactured(meter, CT?,PT?)						Delete Conditional (CUBR) – Required if available, but which devices?	C-D050 DTM02
Cell phone for communications(y/n)						R – MSRP needs this information	R-D070 YNQ01
Pulse output required (y/n)						Delete – this is covered in Pulse Output field	R-D070 YNQ01
Transformer loss compensation (y/n)						R	R-D070 YNQ01
Load research meter required(y/n)						Delete – In AZ another sample will be chosen.	R-D070 YNQ01
Optical port for communications(y/n)						R	R-D070 YNQ01
Meter uses communications other than phone, cellular, or radio(y/n)						Delete – this will be designated under special metering equipment.	R-D070 YNQ01
Phone line dedicated(y/n)						R CUBR – Is required but what if there is no phone?	R-D070 YNQ01
Uses conventional phone line for communications(y/n)						Delete CUBR – Is required but what if there is no phone line?	R-D070 YNQ01
Line Share Switch (y/n)						R	
Power maintained during installation(y/n)						Delete	R-D070 YNQ01
Meter has a radio communicator that passes data through radio waves(y/n)						Delete	R-D070 YNQ01
Number of phases						Delete – this is shown in the form number	R-D100 MEA03
PT quantity (number of PT/VTs at the site)						Delete – CT/VT information will be separated out in specifics. Conditional(CUBR) – Required if available	C-D100 MEA03
CT quantity(number of CTs at the site)						Delete – CT/VT information will be separated out in specifics. Conditional(CUBR) – Required if	C-D100 MEA03

						available	
Pulse multiplier						Delete – this is represented as ke Conditional(CUBR) – Required if available	C-D100 MEA03
Radio communication (y/n)							
Delta/Wye						R	
Register ratio						R	
Number of wires						R	
Number display segments						C	
Manufacturer						R	
Meter Class						R	
New Meter phone number/LSS Port						Conditional	R-D230 COM02
Customer lock cut (y/n)						R	
UDC lock cut (y/n)						R	
Communications device frequency						Delete Conditional(CUBR) – Required if applicable	C-D230 COM02

Approved Meter Data Elements

– Bundled Customer (meter exchange required) to Direct Access

(IDEAL DATA ELEMENTS)

(ELEMENTS WILL BE USED WHEN CREATING THE EDI 650 transaction**)**

STEP #1 **Data from the Enrollment DASR**

Data Element	Size	Type		
Data Elements begin with Step #2				

STEP #2 Metering Information from UDC to MSP/ESP (Existing Meter Information EMI)

Data Element	IG Loc.	UIG	AZ Ideal Data Elements Required = R Conditional = C Optional = O	CUBR
UDC name			R	
UDC Account Number			R	
Business Name (DBA)			C – used if data available – (3-15-00 UDCs recommend keeping this field)	
Customer name	H050 N102	O	R	R-H050 N102
Service address	H070 N3	O	R	R-H070 N3
City/town/county	H070 N4	O	R	R-H080 N4
DASR Tracking Number			C – may not be used for all metering scenarios. (3-15-00 We believe that CUBR is using this field with a different field name)	
Transaction reference number		R	R - This would be valuable for use in the MADEN and in the future for the 824.	R-H020 BGN02
Read cycle number	D030 REF 02	O	R (3-15-00 Conditional(CUBR) – if meter read is based on a cycle)	C-D030 REF02
Medical Monitoring (y/n)	D030 REF 02	O	R	R-D030 REF02
Site meet required (y/n)	D070 YNQ 09	O	R (reasons for site meet may vary within service territories) (3-15-00 CUBR has this in step 3 but not the MI)	
KVARH Metering required (y/n)			R (this indicated whether kvarh is required)	YNQ~~N~9~K VARH
Date EMI sent	H020 BGN 03	R	R	R-H020 BGN03
Equipment purchase authorization/information (EPA) (y/n)			R (3-15-00 CUBR does not have this field -- Changed Associated purchase order to Associated purchase authorization/information)	
Current Tariff Rate	D030 REF 02	O	Required The current rate the customer is on will be sent.	R-D030 REF02
DA Ready (SRP service territory)			Conditional – if UDC allows for ESP to buy metering	
Totalized/Combined Metering (y/n)			R (3-15-00 CUBR doesn’t have this field but they DO handle totalized/combined in the HL segment)	
# of meters for site			R	
Existing Meter Information				
Universal Node Identifier (UNI)			R (3-15-00 CUBR uses SDPI as their UNI)	
Meter number	D030 REF 02	O	R	R-D030 REF02
Serial Number	D030	O	Conditional– SRP may not have serial numbers	O-D030 REF02

	REF 02		assigned to all meters	
Meter Model/type	D030 REF 02	O	R	O-D030 REF02
Meter Form	D030 REF 02	O	R	O-D030 REF02
Meter Class	D100 MEA 03	O	R	R-D100 MEA03
Meter Voltage	D100 MEA 03	O	R	R-D100 MEA03
Register Ratio	D100 MEA 03		Conditional – depends on meter type	C-D100 MEA03
IDR meter (y/n)			R	
Meter pulse constant (Ke)	D100 MEA 03	O	Conditional Conditional(CUBR) – Required if available	C-D100 MEA03
Meter register constant (Kr)	D100 MEA 03	O	Conditional	R-D100 MEA03
Meter disk constant (Kh)			R	
Meter multiplier			R	
KYZ Output	D030 REF 02	O	Conditional – if pulse exists, it will be supplied (3-15-00 Possible discrepancy with CUBRs use of Optional since Disc Constant it Conditional)	O-D030 REF02
No. of Wires	D100 MEA 03	O	R	R-D100 MEA03
Delta/Wye	D030 REF 02	O	R (CUBR calls it the Phase connecting/transformer configuration – Figures are D or W)	C-D030 REF02
Service voltage			R – Conditional(CUBR) – Required if available	C-D100 MEA03
Transformer loss compensation (y/n)			R	R-D070 YNQ01
Current Relationship Information				
ESP name	H050 N102	O	R – while paper forms are used Janie suggested using ticker symbol for name (NEW, APSES, etc) (3-15-00	O-H050 N102
ESP DUNS	H050 N104	O	R – when electronic format is used –EDI 650, CSV	O-H050 N104
MSP name	H050 N102	O	R – while paper forms are used (3-15-00 This is conditional for CUBR since they send meter data out as requested on their 814 which could have no tie to an MSP. For this AZ scenario we MUST know who the MSP is thus a required field.)	C-H050 N104
MSP DUNS	H050	O	R – when electronic format is used – EDI 650,	C-H050 N104

	N104		CSV (3-15-00 Same as MSP Name)	

Scheduling Options				
Exchange Meter			C (3-15-00 Changed this field from R to C – We don't know if CUBR uses this type of field.)	
Upgrade Meter			C (3-15-00 Changed this field from R to C - We don't know if CUBR uses this type of field.	
Instrument Transformer Information				
CT ratio	D030 REF0 2	O	Conditional – required if CTs are present	O-D030 REF02
CT type			Conditional	
CT id number (s)			Conditional	
CT serial number (s)			Conditional	
VT ratio	D030 REF0 2	O	Conditional – required if VT present	O-D030 REF02
VT type			Conditional	
VT id number (s)			Conditional	
VT serial number (s)			Conditional	
Communications Information				
Meter Phone Number			Conditional	
Communications owner			Conditional	R-D030 REF02
Cell phone for communications(y/n)			R	R-D070 YNQ01
Shared Phone Line (y/n)			R	
Dedicated Phone Line (y/n)			R CUBR – Is required but what if there is no phone?	R-D070 YNQ01
Radio communications (y/n)			R	
Access Information				
Meter Location (where meter can be found)	D250 MTX0 2	O	Conditional – if information is present it will be provided	C-D250 MTX02
Read Instructions (special instructions for reading meter)	D250 MTX0 2	O	Conditional – if information is present it will be provided	C-D250 MTX02

Additional Meter Information/Remarks				
Remarks	D250 MTX02	O	Conditional – this field will be used to specify voltage monitoring , special or electrical monitoring equipment (3-15-00 CUBR does not have a remarks field) On customer accounts located in rural areas, some site information may be included in this field.	
XFMR Rating factor			C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	
XFMR Accuracy Class			C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	
XFMR BIL (basic installation level)			C (may be added if xfmrs are sold to ESPs) PENDING DISCUSSION	

STEP #3 Scheduling Information from MSP/ESP to UDC (Meter Data Communication Request MDCR)

Data Element	IG Loc.	UIG	Ideal **Ideal Data Elements** **Required = R** **Conditional = C** **Optional = O**	CUBR
Sender Name (UDC/MSP)			R (4-10 Changed from MSP Name to Sender since this form will be used in other scenarios)	
Receiver Name (UDC/MSP)			R (4-10 Changed from MSP Name to Receiver since this form will be used in other scenarios)	
Date MDCR Sent			R (4-10 added)	
Transaction Ref Number			R (4-10 added)	
DASR #			R	
ESP Name			R	
Customer name			R Required(CUBR)	R-H050 N102
Service Address			R	
City/Town/County			R	
UNI – Universal Node Identifier			R (CUBR) – Required if available	C-D030 REF03
Existing Meter number			R	R-D030 REF02
UDC Account Number			R	R-H100 N102
Scheduled Date (scheduled installation date)	D050 DTM	O	R	R-D050 DTM02
Schedule Notification Type			R (this is to indicate what type of notification the MSP is scheduling)	

Site meet required (Y/N)	D070 YNQ 01	O	R	R-D070 YNQ01
Site meet time			Conditional – If MSP or UDC request site meet, additional coordination is required. The method to confirm site meet date and time may be the use of MADEN or some other exception notice. We would like to keep this for a manual process (forms). A spreadsheet may be needed in the future for when the transaction moves to EDI650.	
Communications to be installed (modem type, phone line installation)			Conditional – SRP can provide MRSP services	O-D030 REF02
Installer (UDC or MSP)			Conditional – SRP can perform these services Required(CUBR) DUNS or DUNS+4	R-D030 REF03
Pending Meter Owner (specific Company or Customer Name)	D030 REF 02	O	R	R-D030 REF02
Its Pending owner (specific Company or Customer Name)			R (In AZ the CT & PTs are sold)	
Its Purchase existing (y/n)			R (In AZ the CT & PTs are sold)	
Totalized/combined equipment purchase (y/n)			R (In AZ the CT & PTs are sold)	
Remarks	D250 MTX 02	O	Optional	

STEP #4 Meter Information from MSP/ESP to UDC (Post Meter Exchange) (Meter Installation/Removal Notification MIRN)

Data Element	IG Loc.	UIG	Ideal	CUBR
UDC Name			R	
Transaction Refr # (???)				
Meter Activity: Meter Exchange/Meter Upgrade/ Meter Removal/Meter Re-program			R	
Date MIRN sent			R (This is for form use only)	R-H020 BGN03
Work completion date	D050 DTM	O	R	R-D050 REF02
New Meter Set Time	D050 DTM	O	R Conditional(CUBR) Required for interval meters.	C-D050 REF03
ESP			R	
MSP			R	
UNI Universal Node Identifier			R	
UDC account number			R	
Service Address			R	
City/Town/County			R	
Customer Name			R	
Business Name			R	
Meter Information/Existing/New				
Existing Meter number			R	
Existing Meter serial number				
Existing Kvarh meter number			C	
Existing Kvarh serial number			C	
New meter number	D030 REF02	O	R	R-D030 REF02
New meter serial number	D030 REF02	O	R	O-D030 REF02
New Kvarh meter number			C	
New Kvarh serial number			C	
New or Change Meter Site Configuration				
Manufacturer			R	
Meter Model type	D030 REF02	O	R	R-D030 REF02
Form number	D030 REF02	O	R	O-D030 REF02
Meter Class			R	
Meter voltage	D100	O	R	R-D100

	MEA03			MEA03
KYZ Output	D030 REF02	O	Conditional – if pulse exists	O-D030 REF02
Most recent calibration test date			R	R-D050 REF02
Optical port(y/n)			R	R-D070 YNQ01
Number display segments			C	
<u>Program ID</u>	D030 REF02	O	Conditional – if SRP is reading meter	O-D030 REF02
Pulse Multiplier (Ke)	D100 MEA03	O	Conditional Conditional(CUBR) – Required if available	C-D100 MEA
# of IDR Channels			R	
KWh number of dials	D100 MEA03	O	Required	R-D100 MEA
KW number of dials	D100 MEA03	O	Conditional	R-D100 MEA
KW decimal value			Conditional	
Kvarh number of dials	D100 MEA03	O	Conditional	R-D100 MEA
Disk constant (Kh)			R	C-D100 MEA03
Register constant (Kr)			Conditional – required if available	R-D100 MEA03
Register ratio			R	
Meter Multiplier			R	
Transformer loss compensation (y/n)			R	R-D070 YNQ01
Site Information				
Number of wires			R	
Delta/Wye			R	
Service voltage			R Conditional(CUBR) – Required if available	C-D100 MEA
Customer lock cut (y/n)			R	
UDC lock cut (y/n)			R	
Communications				
New Meter phone number/LSS Port			Conditional	R-D230 COM02
Cell phone for communications(y/n)			R – MSRP needs this information	R-D070 YNQ01
Shared Phone Line (y/n)			R	

Dedicated Phone L:ine(y/n)			R CUBR – Is required but what if there is no phone?	R-D070 YNQ01
Radio communication (y/n)				
Existing/New Meter Display #/Read				
Existing Meter Date			Conditional – based on meter type	
Existing Meter Time			Conditional – based on meter type	
Existing meter read (kWh)			Conditional – depending on meter type	C-D100 MEA
Existing meter read (kW)			Conditional – depending on meter type	C-D100 MEA
Existing meter read (kvarh)			Conditional	C-D100 MEA
Existing TOU Read Display # (1-12)			Conditional – depending on meter type	

Existing TOU Read (1-12)			Conditional – depending on meter type	
New meter read (kWh)	D100 MEA03	O	R	
New meter read (kW)	D100 MEA03	O	Conditional	
New meter read (kvarh)	D100 MEA03	O	Conditional	
New TOU Read Display # (1-12)			Conditional – depending on meter type	
New TOU Read (1-12)			Conditional – depending on meter type	
New meter display sequence – kWh			R	
New meter display sequence – kW			Conditional	
New meter display sequence - kvarh			Conditional	
Instrument Transformer Info				
CT ratio (this is for new MSP equipment only)	D030 REF02	O	C - In Arizona, MSPs can set their own CT/VT	
CT type (this is for new MSP equipment only)			C	
CT id number (s) (this is for new MSP equipment only)			C	
CT serial number (s) (this is for new MSP equipment only)			C	
CT Use (indoor vs. outdoor) (this is for new MSP equipment only)			C	
VT ratio (this is for new MSP equipment only)			C	
VT type (this is for new MSP equipment only)			C	
VT id number (s) (this is for new MSP equipment only)			C	
VT serial number (s) (this is for new MSP equipment only)			C	
VT Use (indoor vs. outdoor) (this is for new MSP equipment only)			C	
Rated primary volts (this is for new MSP equipment only)			C	
Rated primary amps (this is for new MSP equipment only)			C	

Remarks (comments)	D250 MTX02	O	Optional	
Meter Location	D250 MTX02	O	Conditional – if access changes were made by MSP	C-D2550 MTX02
Read Instructions	D250 MTX02	O	Conditional – if access changes were made by MSP	C-D2550 MTX02

UDC Name		DASR Tracking #		Date EMI Sent			
UDC Account Number		Transaction Ref #		Equip Purchase Auth (EPA) (y/n)			
Customer Name		Read Cycle Number		Current Tariff Rate			
Business Name		Medical Monitoring (y/n)		DA Ready (y/n)			
Service Address		Site Meet Required (y/n)		Totalized/Combined Metering (y/n)			
City/Town/County		Kvarh Meter Req'd (y/n)		# of meters for Site	1 of ______		
Existing Metering Information		**Current Relationship Information**		**Scheduling Options**			
UNI - Univeral Node ID		UDC		Exchange Meter (y/n)			
Meter Number		ESP		Upgrade Meter (y/n)			
Serial Number		MSP					
Model/Meter Type		MRSP					
Meter Form		**Pending DASR Information**					
Meter Class		ESP		**Instrument Transformer Information**			
Meter Voltage		MSP			Phase 1 (A)	Phase 2 (B)	Phase 3 (C)
Register Ratio		MRSP		CT Ratio			
IDR Meter (y/n)		Meter Owner		CT Type			
Meter Pulse Constant Ke		**Communications Information**		CT ID#			
Meter Register Constant Kr		Meter Phone #		CT Serial #			
Meter Disk Constant Kh		Communication Owner		VT Ratio			
Meter Multiplier		Cell Phone (y/n)		VT Type			
KYZ Output		Shared Phone line (y/n)		VT ID #			
No. of Wires	__2__3__4	Dedicated Phn line (y/n)		VT Serial #			
Delta/Wye		Radio Comm (y/n)					
Service Voltage		**Access Information**					
Xformer Loss Comp (y/n)		Meter Location:					
		Mtr Reading Instructions					
		Additional Meter Information / Remarks					
		This would contain information about specialized or totalized equipment. This field can also be used for general comments.					

EXISTING METER INFORMATION (EMI) ARIZONA FORM

Existing Metering Information			
UNI - Univeral Node ID			
Meter Number			
Serial Number			
Model/Meter Type			
Meter Form			
Meter Class			
Meter Voltage			
Register Ratio			
IDR Meter (y/n)			
Meter Pulse Constant Ke			
Meter Register Constant Kr			
Meter Disk Constant Kh			
Meter Multiplier			
KYZ Output			
No. of Wires	__2__3__4		
Delta/Wye			
Service Voltage			
Xformer Loss Comp (y/n)			
Access Information			
Meter Location:			
Meter Reading Instructions			
Instrument Transformer Information			
	Phase 1 (A)	Phase 2 (B)	Phase 3 (C)
CT Ratio			
CT Type			
CT ID#			
CT Serial #			
VT Ratio			
VT Type			
VT ID #			
VT Serial #			
150			

Existing Metering Information			
UNI - Univeral Node ID			
Meter Number			
Serial Number			
Model/Meter Type			
Meter Form			
Meter Class			
Meter Voltage			
Register Ratio			
IDR Meter (y/n)			
Meter Pulse Constant Ke			
Meter Register Constant Kr			
Meter Disk Constant Kh			
Meter Multiplier			
KYZ Output			
No. of Wires	__2__3__4		
Delta/Wye			
Service Voltage			
Xformer Loss Comp (y/n)			
Access Information			
Meter Location:			
Meter Reading Instructions:			
Instrument Transformer Information			
	Phase 1 (A)	Phase 2 (B)	Phase 3 (C)
CT Ratio			
CT Type			
CT ID#			
CT Serial #			
VT Ratio			
VT Type			
VT ID #			
VT Serial #			

APPENDIX M-6.2 METER DATA COMMUNICATION REQUEST (MDCR) ARIZONA FORM DRAFT/EXCEL

Sender:	Receiver:	Date MDCR sent:	Transaction #

DASR #	ESP	Customer	Customer Service Address	City/Town/County	UNI Universal Node Identifier	Existing meter #	UDC Acct #	Scheduled Date	Schedule Notification Type	Site Meet (Y/N)	Site Meet Time	UDC Meter or Comm to be installed (y/n)	Installer (UDC or MSP)	Pending Meter Owner	ITs Pending Owner	ITs Purchase Existing (y/n)	Totalized Equipment Purchase (y/n)

Schedule Notification Types:	
SI =	Schedule Meter Install
RI =	Rescheduled Meter Install
UI =	Unscheduled Meter Install
MR	MR = EMI Response from ESP requ

DASR #	Remarks:

THIS FORM WAS MODIFIED TO FIT 8.5X11 PAPER FOR PRESENTATION AND DOES NOT REPRESENT THE ACTUAL SIZE OF THE FORM

Direct Access Meter Installation/Removal Notification (MIRN) Form/Arizona

DRAFT/EXCEL

UDC and DASR reference number	Meter Activity	
UDC Name ______________	_____ Meter Exchange	Date MIRN sent:
	_____ Meter Upgrade	Work Completion Date:
Transaction Ref # ____________	_____ Meter Removal	New Meter Set Time
	_____ Meter Reprogram	ESP:
		MSP:

Universal Node Identifier (UNI)	UDC Account No:	
Service Address:		City/Town/County
Customer Name:	Business name:	

Meter Information	Existing Meter	New Meter
Meter Number		
Meter Serial Number		
Kvarh Meter Number		
Kvarh Meter Serial Number		

	Existing Meter		New Meter	
	Display #	Read	Display #	Read
Meter Date				
Meter Time				
Total kWh Read				
Total kW Read				
Total Kvarh Reads				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				
TOU Read				

Instrument Transformer Info				Channels
	Phase 1 (A)	Phase 2 (B)	Phase 3 (C)	Unit of
CT Ratio				
CT Type				
CT ID #				
CT Serial #				
CT use (in/out)				
VT Ratio				
VT Type				
VT ID #				
VT Serial #				
VT use (in/out)				
Rated Primary Amps				
Rated Primary Volts				

New or Change Meter Site Configuration	
Meter Configuration	
Manufacturer	
Meter Model Type	
Form Number	
Meter Class	
Meter Voltage	
KYZ Output	
Most recent calibration test date	
Optical Port (y/n)	
# Display Segments	
Program ID Name	
Pulse Multiplier (Ke)	
# of IDR Channels	
kWh number of Dials	
kW number of Dials	
kW decimal values	
Kvarh number of dials	
Disk Constant (Kh)	
Register Constant (Kr)	
Register Ratio	
Meter Multiplier	
XFMR Loss Comp (y/n)	

Site Info	
Number of Wires	___ 2 ___ 3 ___ 4
Delta/WYE	Delta ___ Wye ___
Service Voltage	
Customer Lock Cut (y/n)	
UDC lock cut (y/n)	

Communications	
New Meter Phone #/LSS Port	
Cell Phone (y/n)	
Shared Phone Line (y/n)	
Dedicated Phone Line (y/n)	
Radio Communications (y/n)	

Remarks:

Meter Location:

Read Instructions:

UDC Business Rule Comparison

<u>Process #1</u> - Bundled Customer to Direct Access – (Meter exchange required with Meter Services contracted through ESP)

<u>SRP, TEP, APS – PAGES 1-8</u>
<u>CITIZENS, TRICO, NAVOPACHE – PAGES 9-15</u>

UDC Process Description	SRP	**TEP**	**APS**
Assumptions:	**Phase I** (now until 12/31/00)– Customers with loads of 1mW and above are eligible for competitive metering (MSP). **Phase II** (12/31/00 and beyond) All customers are eligible for competitive metering. Customers with yearly loads of 100,000 kWh and above require installation of IDR metering. SRP can continue to provide metering services upon request.	Customers with loads greater than 20 kW require IDR metering. TEP will no longer provide MSP services to any DA commercial customers or residential customers with loads greater than 20kW.	Customers with loads greater than 20 kW require IDR metering. APS will no longer provide MSP services to any DA commercial customer or residential customers with loads greater than 20kW.
Step 1 – ESP Sends Enrollment DASR *(#1 in Meter Data Element Comparison Document)*	ESP Services receives DASR and forwards pertinent information via SRP's CIS system to Metering SPC.	ESP Services receives DASR and forwards metering information to TEP's Meter Shop SPC.	MAC (Meter Activity Coordinator) receives DASR information electronically from ESP Services.
Step 2 – UDC sends existing meter attributes etc. to MSP/ESP *(#2 in Meter Data Element Comparison Document)*	Metering SPOC sends MI and purchase order if applicable to MSP/ESP via email or fax. Excel document **Timing Requirements:** Sent within 3 workdays of receiving DASR information	Meter Shop sends the MI and purchase order if applicable to ESP or MSP via email or fax. Excel document or PDF. **Timing Requirements**: Sent within 5 workdays of receiving DASR information.	APS MAC send page 1 and 2 of MAC form and purchase order if applicable to MSP/ESP via email or fax. (PDF form). **Timing Requirements:** Sent within 3 workdays of receiving DASR information.

Step 2.1 – What is the period of time that an MSP can not exchange the meter? **(Blackout Window)**	No blackout window	An MSP cannot exchange a meter 5 calendar days prior to a read date.	An MSP can not exchange the meter 6 workdays prior to the first APS read date, through the read window. The read window can be 3-5 workdays
Step 2.2 – What is the process for handling the purchase of CT and PT (VT).	**Who may own?** SRP, ESP, MSP or customer **Are there voltage restrictions?** Zero up to and including 600 volts, SRP, MSP, ESP and customer may own equipment. Greater than 600 volts up to and including 25 kV, SRP, MSP, ESP may own equipment. Greater than 25 kV, SRP will own equipment. Exception: SRP will not sell equipment in the dedicated SRP owned substations regardless of voltage classification. Customer owned substations would be considered on a case by case basis. Buying equipment: - An Equipment Purchase Order will be sent with the MI, which will	Who may own? TEP, ESP, MSP or customer Are there voltage restrictions? Zero up to and including 600 volts, TEP, MSP, ESP and customer may own equipment. Greater than 600 volts up to and including 25 kV, TEP, MSP and ESP may own equipment. Greater than 25 kV, TEP will own equipment. Exception: TEP will not sell CT/PT (VT) equipment located in TEP dedicated substations regardless of voltage classifications. Customer owned substations would be considered on a case by case basis. Buying equipment: An Equipment Purchase	**Who may own?** APS, ESP, MSP or customer Are there voltage restrictions? Zero up to and including 600 volts, MSP, ESP and customer may own equipment. Greater than 600 volts up to and including 25 kV, MSP and ESP may own equipment. Greater than 25 kV, APS will own equipment. Exception: APS will not sell equipment in the dedicated APS owned substations regardless of voltage classification. Customer owned substations would be considered on a case by case basis. Buying equipment: An Equipment Purchase Order will be sent with the MAC Form, which will include equipment pricing and information. Meter – APS will sell new

	include equipment pricing and information. Meter – SRP will sell new and existing meters. CT/PT – SRP will sell new (from stock) and existing CT/PT (VT) Associated Equipment - SRP will sell new (from stock) and existing Associated Equipment What are the costs? What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done? Call Single Point of Contact (SPOC) for coordination of work and SPOC will generate a field order. SPOC will contact MSP when work is complete. Who is responsible for maintenance of CT/PT (VT)? The owner of the equipment is responsible for maintenance of CT/PT (VT).	Order will be sent with the MI which will include equipment pricing and information. Meter – TEP will sell new meters out of stock CT/PT - TEP will sell new (from stock) and existing CT/PT (VT) Associated Equipment - TEP will sell new (from stock) and existing Associated Equipment What are the costs? New Equipment Cost of new meter + $5.00 handling fee Installed equipment What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done? Call TEP Meter Shop for coordination of work and they will generate a field order. The Meter Shop will contact the MSP when the work is complete. Who is responsible for maintenance of CT/PT (VT)?	meters out of stock CT/PT – APS will sell new (from stock) and existing CT/PT (VT) Associated Equipment - APS will sell new (from stock) and existing Associated Equipment What are the costs? Installed equipment: Material/labor minus 5-year depreciation. What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done? Call APS MAC for coordination of work and MAC will generate a field order. MAC will contact MSP when work is complete. Who is responsible for maintenance of CT/PT (VT)? The owner of the equipment is responsible for maintenance of CT/PT (VT).

		The owner of the equipment is responsible for maintenance of CT/PT (VT).	
Step 3 – MSP/ESP sends scheduling information to UDC *(#3 in Meter Data Element Comparison Document)*	MSP returns MI form (bottom half of form) to SPC with estimated scheduling information and pending ownership info. Additional phone coordination is required for site meets. **Timing Requirements**: **<u>Return of Form:</u>** The MI form and the Purchase Order must be returned at least 3 working days prior to the exchange.	MSP sends the MI form back with ownership changes and metering options indicated. Additional phone coordination is required for site meets. **Timing Requirements:** **Return of Form:** The MI form and Purchase Order must be returned 5 workdays prior exchange or install date.	MSP sends page 1 of MAC form back to APS with estimated scheduling information and pending ownership information and signed equipment purchase orders. Additional phone coordination is required for site meets. **Timing Requirements:** **<u>Return of Form:</u>** The MAC Form and the Purchase Order must be returned at least 5 working days prior to the exchange.
Step 3.1 – MSP exchanges meter – When does ESP take responsibility for meter/customer?	In SRP service territory, all MSP metering must be complete 10 workdays prior to the actual DA switch date. Therefore, SRP is still responsible for billing the generation consumption until the switch date. The ESP takes responsibility the first minute after midnight on the switch/read date. If a meter exchange takes place after the switch, the ESP takes responsibility for billing the generation consumption.	ESP takes responsibility upon removal of TEP meter.	ESP takes responsibility for meter/customer the first full 15 minute interval for a commercial customers with loads over 20 kW, that the new meter is in the socket. For customers with residential loads under 20 kW, the ESP would be responsible for the first 60 minute interval.

Step 3.2 – Who is responsible for the usage while the meter is out of the socket during the exchange?	If the switch to DA has not yet taken place (see step 3.1), SRP is responsible for calculating lost registration while the meter is out of the socket. If the switch to DA has already taken place, the MSP is responsible for calculating the lost registration. The method we suggest for calculating the lost registration- Take current registration for a certain period of time, beginning and end. Stopwatch check. $\dfrac{\text{\# of Revolutions X Kh X 3.6}}{\text{Time in Seconds}}$ This should give the kW X multiplier.	ESP takes responsibility of consumption once MSP removes TEP meter.	If the meter is out of the socket during the exchange greater than 15 minutes, APS requires the MSP to calculate the "lost registration" and add it to the out-read on the APS meter. A stopwatch check will be used to calculate lost registration.
Step 4 – MSP/ESP sends information about newly installed meter and required UDC meter information to the UDC. *(#4 in Meter Data Element Comparison Document)*	**Timing Requirements**: **<u>Return of Form:</u>** MSP must return the Exchange/Removal/Read form within 2 workdays after install day. This form can be returned by email or fax. **<u>Return of Meter:</u>** The SRP meter must be returned within 5	**Timing Requirements**: **<u>Return of Form:</u>** MSP must return the Meter Activity Form within 3 workdays of install or exchange. **<u>Return of Meter:</u>** The meter must returned to TEP within 15 calendar days of removal. This form can be returned by	**Timing Requirements:** **<u>Return of Form:</u>** MSP must return Page 2 of the MAC form no later than 3 working days from the day of the exchange. Additionally, the form must be returned before the Blackout Window. **<u>Return of Meter:</u>** The meter must be

	workdays after the install date. The meter must shipped or delivered to the 1 office listed on form or website. **<u>Charge for damaged SRP equipment or equipment not returned:</u>** SRP will charge the remaining net book value of the meter.	email or fax. The meter can be shipped or dropped off at 2 offices listed on website. **<u>Charge for damaged TEP equipment or equipment not returned:</u>** Original purchase price of equipment	returned to APS within 15 workdays of removal. This form can be returned by email or fax. The meter can be shipped or dropped off at 5 offices listed on form and website. **<u>Charge for damaged APS equipment or equipment not returned:</u>** Replacement cost minus 5 years depreciation plus 15% handling fee
Step 5 – Billing ESP, MSP, customer for equipment, work performed, non-returned meters, site meet charges, etc.	SRP will bill ESP, MSP or customer at least monthly for equipment, work performed, non-returned meters, site meet charges, etc from the previous month.	TEP will bill ESP, MSP or customer at least monthly for equipment, work performed, non-returned meters, site meet charges, etc from the previous month.	APS will bill ESP, MSP or customer at least monthly for equipment, work performed, non-returned meters, site meet charges, etc from the previous month.
MISC BUSINESS PROCESSES:	**SRP**	**TEP**	**APS**
Handling of Load Research for customers going DA	SRP will select another sample. Load research meters interrogated by phone utilize the customer's phone lines. SRP may lease SRP phone lines.	<u>In most cases,</u> TEP will select another sample. TEP will not allow third parties to use TEP owned phone lines. <u>TEP will not select another sample for customers served under Rate 14 and will be evaluated on a case by case basis.</u>	APS will select another sample. They will disconnect any APS dedicated phone line.
Site Meet & Scheduling Policy	**<u>When is site meet required?:</u>** Site meets are required for all SRP owned dedicated substations and may be required for customer loads 1 mW or greater or when other special metering equipment is in place, at	**<u>When is site meet required?:</u>** Site meets are required for all TEP owned dedicated substations and may be required for customer loads 1 mW or greater or when other special metering equipment is in place, at	**<u>When is site meet required?:</u>** <u>S</u>~~S~~ite meets are required for all APS owned dedicated substations and may be required for customer loads 1 mW or greater or when other special metering equipment is in place<u> or</u>

	the discretion of the SRP. **Scheduling:** MSP returns MI form to SPOC with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 3 working days prior to the exchange. **Site Meet Charges:** SRP will charge $25.00 per site for site meets requested by SRP or MSP. **Changes to Schedule:** If there are changes to the anticipated meter exchange time/date – the MSP must notify SPOC of changes to their schedule by 2 p.m. (Arizona Time), 1 workday prior to the exchange date. **MSP Missed Appointment:** Per protocol we can charge the ESP 1-hour labor time ($85) for failure to show. We recommend the journeyman would consider the site meet a no show after waiting at the site for 30 minutes past agreed meeting time. This charge includes 30 minutes waiting time and 30 minutes travel time to and from site. The	the discretion of the TEP. **Scheduling:** MSP returns the MI form with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 5 working days prior to the exchange. **Site Meet Charges:** TEP will charge $37.00 per hour during normal working hours (6:00 a.m. to 2:30 p.m.) and $55.00 during after hours (2:31 p.m. to 5:59 a.m.) **Changes to Schedule:** If there are changes to the anticipated meter exchange time/date – the MSP must notify TEP of changes to their schedule by 2 p.m. (Arizona Time), 1 workday prior to the exchange date. **MSP Missed Appointment:** If the MSP fails to arrive within 30 minutes of the appointment time, or if the MSP fails to cancel at least one working day in advance, TEP will charge $37.00 for missed appointments during working hours and $55.00 for after hour appointments. **TEP Missed Appointment:** The ESP/MSP may charge TEP based on the same conditions set forth	other arrangements are necessary., at the discretion of the APS. **Scheduling:** MSP returns Page 1 of MAC form and EPO with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 5 working days prior to the exchange. **Site Meet Charges:** APS may charge ESP $30.00 per site for Phoenix Metropolitan area and $75.00 per site for all other areas for a site meet requested by MSP. APS may assess an additional charge of $30.00 per hour for site meets that exceeds 30 minutes. **Changes to Schedule:** If there are changes to the anticipated meter exchange time/date – the MSP must notify APS of changes to their schedule by 2 p.m. (Arizona Time), 1 workday prior to the exchange date. **MSP Missed Appointment:** If the MSP fails to arrive within 30 minutes of the appointment time, or if the MSP fails to cancel at least one working day in advance, APS may charge $30.00 per site for Phoenix Metropolitan area and $75.00 per site for all other areas.

	journeyman will leave a meter tag/hanger telling the MSP whom to contact for rescheduling the appointment. When possible a next day site meet can be coordinated. **SRP Missed Appointment:** 1-hour of labor time will be credited to the ESP's account. The MSP must leave a meter tag indicating that they were at the site. The MSP must wait 30 minutes past the agreed upon time before the appointment can be considered a no-show.	in TEPs requirements of the ESP/MSP.	**APS Missed Appointment:** No current policy exists

Access Issues /Key Process Issues: Keys cannot be copied Liability – customer auth. Locking types: double hasp Lock boxes, utility locks, etc.	**Customer Access Issues:** MSP will need to make arrangements with the customer to gain access to customers' metering equipment. SRP will be unable to provide customer keys to MSPs/ESPs. In order to ensure necessary site access in the event of an emergency, the MSP must notify SRP within 3 working days of any changes in meter access at a customer site. **Utility Access Issues:** If there is just an SRP lock at the site, the MSP will be charged a standard hourly rate (See Services & Fees) to cut the lock in lieu of a site meet. The MSP will install a square D padlock hasp in order to accommodate the MSP and SRP lock. The MSP will also need to install a _____ seal with their name or logo on the seal where the SRP lock would normally be installed in order to properly secure the padlock hasp. The MSP must advise us on the Exchange/Removal/Read form that the lock was cut. **Note**: If MSP installs their own lock, a square D padlock hasp is required.	**Customer Access Issues:** MSP will need to make arrangements with the customer to gain access to customers metering equipment. TEP will be unable to provide customer keys to MSPs/ESPs. **Utility Access Issues:** If there is just a TEP lock at the site, the MSP will be charged the cost of the lock plus $5.00 admin. and handling fee to cut the lock in lieu of a site meet. The MSP will install a square D padlock hasp or chain in order to accommodate the MSP and TEP lock. The MSP will also need to install an orange seal with their name or logo on the hasp where the TEP lock would normally be installed in order to properly secure the padlock hasp. The MSP must advise us on the MA form that the lock was cut. **Note**: If MSP installs their own lock, a square D padlock hasp is required.	**Customer Access Issues:** MSP will need to make arrangements with the customer to gain access to customers metering equipment. APS will be unable to provide customer keys to MSPs/ESPs. In order to ensure necessary site access in the event of an emergency, the MSP must notify APS within 3 working days of any changes in meter access at a customer site. **Utility Access Issues:** If there is just an APS lock at the site, the MSP will be charged the cost of the lock plus 15% handling fee to cut the lock in lieu of a site meet. The MSP will install a square D padlock hasp in order to accommodate the MSP and APS lock. The MSP will also need to install a blue seal with their name or logo on the hasp where the APS lock would normally be installed in order to properly secure the padlock hasp. The MSP must advise us on page 2 of the MAC form that the lock was cut. **Note**: If MSP installs their own lock, a square D padlock hasp is required.

UDC Process Description	Citizens Utilities (CUC)	Trico	Navopache
Assumptions:	Customers with loads greater than 20 kW require IDR metering. CUC will no longer provide MSP services to any DA commercial customers or residential customers with loads greater than 20kW.	Customers with loads greater than 20 kW require IDR metering. Coops can provide MSP services to any DA commercial customer or residential customers as long as they are not competing outside of the service territory R14-2-1615C.	Customers with loads greater than 20 kW require IDR metering. Coops can provide MSP services to any DA commercial customer or residential customers as long as they are not competing outside of the service territory R14-2-1615C.
Step 1 – ESP Sends Enrollment DASR *(#1 in Meter Data Element Comparison Document)*	ESP Services receives DASR and forwards metering information to CUC's Meter Shop.	DASR is provided by ESP, with read window specified, and is forwarded to Trico's metershop.	ESP provides DASR 5 workdays prior to switch. MSP must give 5 days notice of joint meet.
Step 2 – UDC sends existing meter attributes etc. to MSP/ESP *(#2 in Meter Data Element Comparison Document)*	Meter Shop sends the MI and purchase order if applicable to ESP or MSP via email or fax. Excel document or PDF. **Timing Requirements**: Sent within 5 workdays of receiving DASR information.	Trico's metershop sends back the Meter Information form with requirements for site meet, and purchase order if applicable. This will be sent via email in an Excel Spreadsheet or by fax. **Timing Requirements:** Will be sent within 5 workdays of receiving the original DASR.	NEC Metering sends the MI to ESP/MSP via email or fax. Excel document or PDF. **Timing Requirements**: Sent within 3 workdays of receiving DASR information.
Step 2.1 – What is the period of time that an MSP can not exchange the meter? **(Blackout Window)**	No blackout window	Trico will maintain a 5 day blackout period around the read date. The consumer will switch on exchange date, rather than the read date, maintaining the need for partial bills to their consumers.	An MSP can not exchange a meter 5 calendar days prior to read date.

Step 2.2 – What is the process for handling the purchase of CT and PT (VT).	**Who may own?** CUC, ESPor MSP **Are there voltage restrictions?** Zero up to and including 600 volts, MSPor ESP may own equipment. Greater than 600 volts up to and including 25 kV, MSP and ESP may own equipment. Greater than 25 kV, CUC will own equipment. Exception: CUC will not sell equipment in the dedicated CUC owned substations regardless of voltage classification. Customer owned substations would be considered on a case by case basis. Buying equipment: An Equipment Purchase Order will be sent with the MI Form, which will include equipment pricing and information. Meter – CUC will not sell new meters out of stock CT/PT – CUC will not sell new (from stock) but will sell existing CT/PT (VT) Associated Equipment - CUC will not sell new (from stock) but will sell existing Associated Equipment	**Who may own?** Trico only **Are there voltage restrictions?** **N/A** **Buying Equipment:** **N/A** **What are the costs?** **N/A** **What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done?** Joint meeting required to perform accuracy test of instrument transformers. Trico's metershop will perform accuracy test of the entire meter system, and will provide on site testing and necessary repairs. Trico's charge is $250 per instrument rated site.	**Who may own?** Navapache only **Are there voltage restrictions?** N/A **Buying equipment:** N/A **What are the costs?** N/A **What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done?** Joint meeting required to perform accuracy test of instrument transformers.

	What are the costs? Installed equipment: Undetermined at this time What happens if the MSP finds that the existing CT/PT (VT) equipment is damaged before exchange is done? Call CUC MAC (Meter Activity Coordinator) for coordination of work and a field order will be generated. The MSP will be contacted when the work is complete. Who is responsible for maintenance of CT/PT (VT)? The owner of the equipment is responsible for maintenance of CT/PT (VT).		
Step 3 – MSP/ESP sends scheduling information to UDC *(#3 in Meter Data Element Comparison Document)*	MSP sends the MI form back with ownership changes and metering options indicated. Additional phone coordination is required for site meets. **Timing Requirements:** **<u>Return of Form:</u>** The MI form and Purchase Order must be returned 5 workdays prior exchange or install date.	Trico or the MSP sends Meter Information form back to ESP with ownership changes and if needed, phone coordination required for site meet. **Timing Requirements:** **<u>Return of Form:</u>** The MDCR form must be returned within 5 workdays prior to exchange, site meet or installation date.	MSP sends MI form back with ownership changes and metering options indicated. Additional phone coordination is required for site meets. **Timing Requirements:** The MI form must be returned 5 workdays prior to exchange or installation date.
Step 3.1 – MSP exchanges meter – When does ESP take responsibility	ESP takes responsibility upon removal of CUC meter.	The ESP shall be responsible upon the 1st 60 minute interval after the meter	When the final meter reading is taken, or at 12:01 on the first day of the next billing cycle

for meter/customer?		exchange.	following meter exchange.
Step 3.2 –Who is responsible for the usage while the meter is out of the socket during the exchange?	ESP takes responsibility of consumption at the time CUC's meter is removed. The MSP is responsible for calculating the lost registration. A stopwatch check or other acceptable measuring method should be used to estimate unmetered consumption.	Once Trico's meter is removed the ESP/MSP is responsible. **Will we use stopwatch check?** Yes, this is acceptable. **Who will calculate the lost registration ?** The ESP, MSP & Trico will participate as needed.	ESP/MSP is responsible after the UDC meter has been removed.
Step 4 – MSP/ESP sends information about newly installed meter and required UDC meter information to the UDC. *(#4 in Meter Data Element Comparison Document)*	**Timing Requirements**: **<u>Return of Form:</u>** MSP must return the Meter Activity Form within 3 workdays of install or exchange. **<u>Return of Meter:</u>** The meter must returned to CUC within 15 calendar days of removal. This form can be returned by email or fax. The meter can be shipped or dropped off at 3 offices listed on website. **<u>Charge for damaged CUC equipment or equipment not returned:</u>** **Undetermined at this time**	**Timing Requirements:** **<u>Return of Form:</u>** The MSP must return meter activity form within 5 working days from the day of the exchange. **<u>Return of Meter:</u>** The meter must be returned to Trico within 5 workdays of removal. The meter can be shipped or dropped off at our Ina Road location. **<u>Charge for damaged Trico equipment or equipment not returned on time:</u>** Trico will require the replacement cost of the meter/meter system.	**Timing Requirement:** MSP must return meter activity form within 5 calendar days. This form may be returned by fax or email.
Step 5 – Billing ESP, MSP,	CUC will bill ESP, MSP or customer at least monthly	Trico will bill ESP, MSP or consumer at	NEC will bill ESPs/MSPs once per

customer for equipment, work performed, non-returned meters, site meet charges, etc.	for equipment, work performed, non-returned meters, site meet charges, etc from the previous month.	least once per month for all equipment and work performed from the previous month.	month for all equipment and work performed from the previous month.
MISC BUSINESS PROCESSES:			**Other**
Handling of Load Research for customers going DA	CUC will select another sample. They will disconnect any CUC dedicated phone line.	Trico will select another sample site and will disconnect any Trico dedicated phone line, or communication hardware.	NEC will select another sample and will disconnect any communications hardware.
Site Meet & Scheduling Policy	**When is site meet required?:** Site meets are required for all CUC owned dedicated substations and may be required for customer loads 1 mW or greater or when other special metering equipment is in place, at the discretion of the CUC. CUC will take any required primary system outages for CT/PT exchanges due to safety considerations. **Scheduling:** MSP returns the MI form with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 5 working days prior to the exchange. **Site Meet Charges:** Undetermined at this time **Changes to Schedule:**	**When is site meet required?:** Trico will require a site meet for anything that is not self-contained (no CT/PT (VT)). **Scheduling:** MSP returns the MI form with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 5 working days prior to the exchange. **Site Meet Charges: Trico may charge a** service fee of $75 per site meet and $30 per man-hour for site meets that exceed 30 minutes. These meets are subject to our	

	If there are changes to the anticipated meter exchange time/date – the MSP must notify CUC of changes to their schedule by 2 p.m. (Arizona Time), 1 workday prior to the exchange date. **MSP Missed Appointment:** If the MSP fails to arrive within 30 minutes of the appointment time, or if the MSP fails to cancel at least one working day in advance, CUC may charge a fee (amount to be determined). **CUC Missed Appointment:** The ESP/MSP may charge CUC based on the same conditions set forth in CUC's requirements of the ESP/MSP.	overtime rates. **Changes to Schedule:** No charges with 48 hours notice to Trico. **MSP Missed Appointment:** If the MSP fails to arrive within 30 minutes of the appointment time, or if the MSP fails to cancel at least one working day in advance, Trico may charge a fee of up to $75. **Trico Missed Appointment:** If the Trico fails to arrive within 30 minutes of the appointment time, or if Trico fails to cancel this appointment at least one working day in advance, Trico may credit the labor time or pay a fee of up to $75. **Meter Changed W/O 5 day notice:** Trico may charge a fee of up to $75. There may also be a charge of $10 per each 15 minutes of time wasted on the meter readers route.	
	Customer Access Issues: MSP will need to make arrangements with the customer to gain access to customers metering	**Customer Access Issues:** MSP will need to make arrangements with the consumer to	NEC will not provide any utility keys to ESP/MSP. NEC prefers double hasp.

	equipment. CUC will be unable to provide customer keys to MSPs/ESPs. **Utility Access Issues:** If there is just a CUC lock at the site, the MSP will be charged the cost of the replacement lock plus a handling fee (to be determined) to cut the lock in lieu of a site meet. A double hasp will be provided by the MSP at all installations to accommodate a CUC padlock. The MSP will also need to install a gold seal with their name or logo on the hasp where the CUC lock would normally be installed in order to properly secure the padlock hasp. The MSP must advise us on the MI form that the lock was cut. Note: If MSP installs their own lock, a square D padlock hasp is required. If a door lock is changed by the MSP, a key will be provided for the UDC.	gain access to the consumers metering equipment or site. Trico is unable to provide customer keys to MSPs/ESPs. The UDC requires access to metering equipment on the customer's premise for safety reasons and already have keys that were supplied by the customer. The ESP should be responsible for supplying the UDC with a key to any lock changed on the customer's metering room. It is not reasonable to require the customer to produce another key for the UDC. **Utility Access Issues:** If there is just a Trico lock at the site, the MSP will be charged a standard hourly rate (See Trico's Services & Fees Schedule) to cut the lock in lieu of a site meet. The MSP will install a square D padlock hasp or a Moore Lock/Lockbox in order to accommodate the MSP and Trico. The MSP will also need to put, engrave or label, their name or logo on the lock where Trico's lock would normally	

		be installed in order to properly secure the padlock hasp. The MSP must advise Trico on the Exchange/Removal/Read form that the lock was cut and/or changed out.	

APPENEDIX M-8

Status of Proposed Arizona Best Practice for

Bundled Customer to Direct Access

(Meter exchange required with Meter Services Contracted with ESP)

This document identifies the process description and proposed best practice of a customer switching from UDC Standard Offer to Direct Access Service.
The information contained in the document is based on current and proposed business practices identified by APS, SRP, Tucson Electric Power Company and Co-ops.
Many of the practices are pending resolution and are being reviewed and discussed by Market Participants and UDCs.
This document is a working DRAFT and only represents the positions of the aforementioned Utilities.

Legend:

RC = ACC Competition Rule Change Required	UPP = UDC and Provider Process, NO ACC action needed
CSI = Clarification of Staff's Interpretation	N/A = No Action Needed
UTC = Utility Tariff/Article/Protocol Change Required	NC = No Consensus

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
	Assumptions:							
	Step 1 – ESP Sends Enrollment DASR *(#1 in Meter Data Element Comparison Document)*	The DASR Group will handle any standardization needed. This however, is the first high level step in the entire process					X	
	Step 2 – UDC sends existing meter attributes etc. to MSP/ESP *(#2 in Meter Data Element Comparison Document)*	**Form Name:** The form that the UDCs will use to communicate existing meter attributes to MSP/ESP will be called the **EMI** (Existing Meter Information) Form. **Timing Requirements**: The EMI and the Equipment Purchase Authorization (EPA) will be sent within 5 workdays of receiving DASR information			X	X		

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
53	**Step 2.1 –** What is the period of time that an MSP cannot exchange the meter? **(Blackout Window)**	Pending further discussion						
	Step 2.2 – What is the process for handling the purchase of CTs and VTs and associated equipment.	Pending further analysis, review and discussion						
	The first step was to determine voltage level – this shows the ACC rule	Voltage level for ownership: • Zero up to and including 600 volts • Greater than 600 volts up to and including 25 kV • Greater than 25 kV					X	
	ACC rules indicate who may own but discussion generated a need for clarification on the best practice for who will own	• Who may own Instrument Transformers at each voltage level: • UDC • ESP • MSP • Customer • • See UDC Business Rule Comparison document for each UDC's rules (Appendix M-8).						**X** The only difference is that SRP may own at all voltage levels and TEP & APS will only own greater than 25 kV
		Buying Equipment: **Meters:** See UDC Business Rule Comparison document for each UDC's rules (Appendix M-8).						**X** UDC processes are the same with the exception that SRP will sell the existing meter in the field and TEP, APS & Co-ops will not.

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
		• **CT/PT (VT):** UDC"s will sell new (from stock) and existing CT/PT (VT)				X		
		• **Associated Equipment:** UDCs will sell new (from stock) and existing Associated Equipment				X		
		Equipment Costs: See UDC Business Rule Comparison document for each UDC's rules (Appendix M-8).					X	
		Process for handling damaged/altered equipment discovered by the MSP <u>before</u> exchange is done Call the UDCs Metering Point of Contact for coordination of work and the UDC will generate a field order. The UDC will contact MSP when the work is complete.			X	X		
		Responsibility for maintenance of CT/PT (VT): Maintenance and servicing of metering equipment will be limited to the UDC, the ESP, or the MSP.			X		X	

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
40	**Step 3** – MSP/ESP sends scheduling information to UDC *(#3 in Meter Data Element Comparison Document)*	**Form Name:** The name of the form that the MSPs will use to communicate scheduling information to the UDCs will be called the **MDCR** (Meter Data Communication Request) Form. **Timing Requirements:** **<u>Return of MDCR Form</u>:** The MDCR Form and the EPA (if applicable) must be returned at least 5 working days prior to the exchange.			**X**	**X**		
35	**Step 3.1 –** MSP exchanges meter – When does ESP take responsibility for meter/customer?	**Pending further discussion**						
35	**Step 3.2 –** Who is responsible for the usage while the meter is out of the socket during the exchange?	**Pending further discussion**						
	Step 4 – MSP/ESP sends information about newly installed meter and required UDC meter information to the UDC. *(#4 in Meter Data Element Comparison Document)*	**Form Name:** The name of the form that the MSPs will use to communicate information about newly installed meters and UDC meter information to the UDCs will be called the **MIRN** (Meter Installation/Removal Notification) Form.			**X**	**X**		
		Timing Requirements: **<u>Return of Form</u>:** MSP must return MIRN form no later than 3 working days from the day of the exchange.			**X**	**X**		

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
		<u>Return of Meter:</u> The meter must be returned to the UDC within 15 working days of the removal. **Note:** Drop off sites/shipping options will vary between UDCs.			X	X		
		<u>Charge for damaged UDC equipment or equipment not returned:</u> See UDC Business Rule Comparison document for each UDCs rules (Appendix M-8)					X	
	Step 5 – Billing ESP, MSP, customer for equipment, work performed, non-returned meters, site meet charges, etc.	UDCs will bill ESP, MSP or customer at least monthly for equipment, work performed, non-returned meters, site meet charges, etc from the previous month.				X		
	MISC BUSINESS PROCESSES:							
37	**Handling of Load Research for customers going DA**	If a current load research account switches to DA, TEP, SRP, APS & Co-ops will select another sample. The handling of the existing phone lines may vary. See UDC Business Rule Comparison document for each UDC's rules (Appendix M-8)				X		

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
68	Site Meet & Scheduling Policy	**<u>When is site meet required?:</u>** Site meets are required for all UDC owned dedicated substations and may be required for customer loads 1 mW or great or when other special metering equipment is in place, at the discretion of the UDC.				X		
		<u>Scheduling:</u> MSP returns the MDCR and EPA form with estimated scheduling information and pending ownership information. Additional phone coordination is required for site meets. Timing Requirements: Form must be returned at least 5 working days prior to the exchange.				X		
		<u>MSP Missed Appointments</u> If the MSP fails to arrive within 30 minutes of the appointment time, or if the MSP fails to cancel at least one working day in advance, the UDC may charge. For charge information see UDC Business Rule Comparison document for each UDCs rules (Appendix M-5)				X		
		<u>UDC Missed Appointment:</u> See UDC Business Rule Comparison document for each UDCs rules (Appendix M-8)				X		

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
		<u>Site Meet Charges:</u> See UDC Business Rule Comparison document for each UDC's rules (Appendix M-8)					X	
		<u>Changes to site meet Schedule:</u> If there are changes to the anticipated meter exchange time/date – the MSP must notify the UDC of changes to their schedule by 2 p.m. (Arizona Time), 1 workday prior to the exchange date.				X		
33	**Access Issues** Key Process Issues: Keys cannot be copied Liability – customer auth. Locking types: double hasp Lock boxes, utility locks, etc.	**Customer Access Issues:** **Customer Lock:** MSP will need to make arrangements with the customer to gain access to customers' metering equipment. Utilities will not provide customer keys to MSPs/ESPs. In order to ensure necessary site access in the event of an emergency, the MSP must notify the Utility on the MIRN within 3 working days of any changes in meter access at a customer site.				X		

Issue #	UDC Process Description	Proposed Arizona Best Practice	RC	CSI	UTC	UPP	N/A	NC
33 (Cont'd)	**Access Issues (Cont'd)**	**Utility Lock:** If there is just a Utility lock at the site, the MSP can cut the lock. The MSP must install a square D padlock dual-hasp in order to accommodate the MSP and utility lock. The MSP will also need to install a _____ seal with their name or logo on the seal where the utility's lock would normally be installed in order to properly secure the padlock hasp. The MSP must advise the Utility on the MIRN form that the lock was cut. The ESP or MSP may be charged for the lock in accordance to the Utility's applicable service fees. The ESP and MSP can request a site meet with the UDC to gain access. Site meet charges may apply.				**X**		

APPENDIX M-9

HIGH LEVEL FLOW - PROCESS # 1
BUNDLED CUSTOMER TO DIRECT ACCESS
(METER EXCHANGE CONTRACTED WITH ESP)